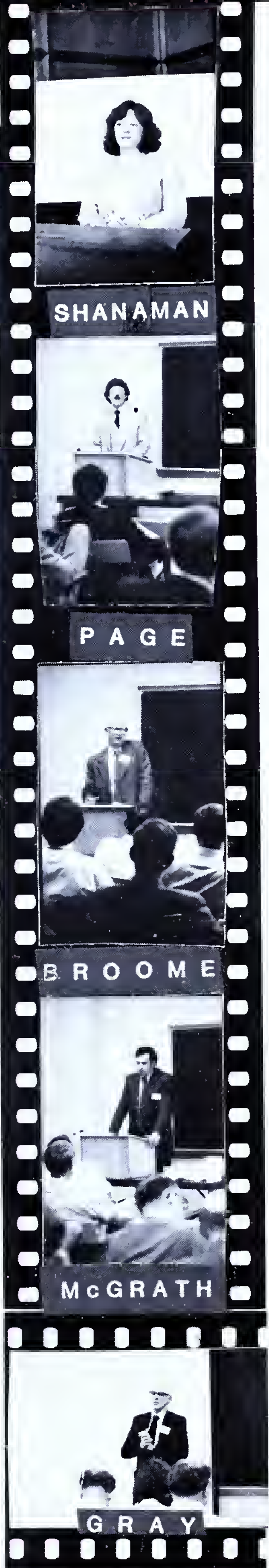

1981 Hydropower

PROCEEDINGS

Co Hosted With

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P. O. BOX 3265, HARRISBURG, Pa. 17120

May 12&13 at Harrisburg, Pa.

COMMONWEALTH of VIRGINIA
State Office of Emergency and Energy Services

May 28&29 at VPI, Blacksburg, Va.

PREFACE

Hydropower was not among the main topics of conservation and certainly not an alluring investment venture until recently. In the late fifties and early sixties more hydroelectric facilities were being retired from active service than were coming on line. Then the oil embargo became a reality, cheap oil disappeared from the marketplace, and energy became the challenge of the century.

The challenge has now overflowed into the eighties, but results are being realized from the efforts expended in the last century. The Corps of Engineers Report of July 1977 indicated significant hydropower potential in the USA; by December 1978 the first demonstration project award was made. By April 1980 the first loan was awarded for a feasibility study and the first demonstration project came on line in August.

A meeting of the minds - a workshop - was considered timely to discuss the "state of the art," to disseminate available printed matter, to assess our position and to evaluate the future. Two locations were chosen in early February for their accessibility and geographic potential for meaningful field trips.

It was thought that if the private sector was to handle small scale hydro development, then everyone should be heard, especially the financial entities. The availability of individuals with expertise and their willingness to participate contributed to the success of two most informative workshops. The publication of manuals on private and public financing by the Energy Law Institute stimulated discussions and presented new ideas to the attendees.

Your attendance and participation were greatly appreciated. The speakers who gave of their time and talent in exceeding the quality of any previous seminars of this type are to be commended. We are equally grateful to the host states for their significant contributions.

We trust that these proceedings will serve as a ready source of information. Although there were two locations, only one volume was prepared. This permitted the state-specific items of both host states to be included under one cover. Hopefully your copy will serve as a ready reference, as well as a pleasant reminder of the 1981 Hydropower Workshop in your area.

ACKNOWLEDGEMENT

A portion of the outreach function of the Small Scale Hydro program was originated by the program manager, Mr. Ed Gray, with approval and funding from the national level of the Department of Energy. Our 1981 workshops were scheduled to coincide with the publishing of the finance manuals developed by the Energy Law Institute.

We are most grateful for the willing participation of all speakers and panelists whose contributions are infused in this volume. Others, on and behind the scenes, are acknowledged and given the thanks they so richly deserve.

The Pennsylvania Public Utility Commission agreed to co-host the first workshop. Its success resulted largely from the administrative and planning efforts of Mr. Frank Pilling. We are certain that he will share our thanks with his co-workers who performed their assigned functions so admirably.

The use of the Virginia Polytechnic Institute facilities in Blacksburg presented different problems for the Virginia State Office of Emergency and Energy Services in Richmond. Those problems were resolved by Ms. Kathryn Gearheart who developed the cooperation necessary for a successful seminar.

A special word of thanks goes to our program manager, Mr. Ed Gray for an outstanding job and to Mr. Al Ioppolo, his co-worker, who made this volume possible. We hope you will find it useful.

William Kaplan, Director
Philadelphia Support Office
of the
Chicago Operations Office
U. S. Department of Energy

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WELCOME
as delivered in Blacksburg, Virginia, May 28, 1981

Edgar L. Gray
Small Scale Hydro Program Manager
Region III, Department of Energy
Philadelphia, PA

I'm Ed Gray. I have the shortest name in Energy. Once we had a fellow by the name of Al Metz; we shipped him out so I could have the sole possession of this questionable honor.

Last night there was some discussion that I should not -- since I am from north of the Mason-Dixon Line -- be welcoming Virginians to a Virginia conference. I want to make it perfectly clear that I am not doing that because this isn't DOE's workshop; nor is it the Governor's Energy and Emergency Services, who are co-hosting. It is not their conference either; it is <u>your</u> conference. I say this because we have so many occasions, particularly in today's world, when we can't control people becoming victims of another person's ignorance. I refer particularly to the recent acts of terrorism -- the attempted assassinations on the Pope and the President, and it is most difficult to control such occurrences. But to have people victimized by their own ignorance is something that can be controlled, and that is the reason for this workshop.

Actually, you will get as much out of it as you put in it. We have tried to get the best expertise that we can on the various subjects which we know are near and dear to those of you who are contemplating hydropower in your future. We feel that if you participate and you ask questions, then we're going to have a very nice intimate working group.

Originally we were scheduled to have the rear portion of the auditorium, and when I saw the registration I figured that we should compact it; use a smaller facility where we can get together and get to know one another.

It seems that every time we schedule one of these workshops that we have what I call "hydroweather" or lots of rain, if you prefer. We had one in Harrisburg two weeks ago, and they had a tornado watch. I kept getting calls the following day from drought-plagued Florida saying, "Hey, come on down; we need you." I told them, "You are not in my territory."

One of the reasons for communication being the hardest function that we human beings attempt is that we don't work at it seriously enough. It's very difficult to communicate. Many times we think that we're being understood, but if we consider our divorce rate, we know doggone well that people aren't communicating. So this is why I think that communication is so very important. The speakers have gone over what they feel you want to hear. If they are not telling you what you want to know, please ask.

I had a recent problem or difficulty with communication. At Harrisburg I referred to an old incident and people don't like the old ones, so I thought I'd bring you up to date on a communication error that happened not too long ago.

Now I consider myself to be a fairly decent judge of horse flesh (the trainers, jockeys, track variants and imposts present problems). I will say that the state of Virginia has produced some great Triple Crown winners in the last few years. It has been one of my failings for the last dozen years to attend the Preakness. I feel that it is halfway between Churchill Downs and Belmont. I might as well go there because I know that track a little better. The turns are tighter, the stretch is longer, so I feel more at home at the Pimlico oval. This year I had a few extra tickets and I invited some friends. Now those friends shall remain nameless because of the embarassment of the incident. I told them, by phone, "I'll meet you at the East grandstand gate between ten and ten-thirty." I gave them the time and the place. Then I asked, "Have you been to the Pimlico racetrack?" "Oh, we'll find it, we'll find it."

Saturday, I show up on time and they're not there. So I get to thinking that they might have gone to the West gate. The stretch at Pimlico is 1152 feet long to the finish line and then you go far beyond that, way over to the other side, to get to the West gate. I go over to the West gate and, you know, it's hard when you're in a crowd of 84,500 people -- soon they all begin to look alike. But my friends are not there. So I walk back, and then I make another trip, and I walk back. Actually, I covered more mileage than most of the horses that day. So finally, about one o'clock, I gave up. I went in and decided to enjoy the festivities. As you may know, there are no telephones at race tracks (for obvious reasons there are no public phones). This eliminated communication other than the initial conversation. Later in the evening I called and asked, "Hey, where were you?" And they, in turn, asked, "Where were you?" So that's what a communication failure will cause. If you don't understand each other, you can have a very frustrating day. By the way, they were waiting at the clubhouse entrance -- I can't afford all that luxury.

As you know, the only thing that a host, a chairman or a moderator can do is make certain that the program doesn't drag. You have no control over what the speakers will say or anything like that. You can't. So I've tried to select speakers who have the necessary information and know their subject.

I hope that when we ring the curtain down on this particular workshop that everybody is going to leave with the satisfaction that they gained something from their participation in the seminar. I ask you to participate very freely. Regardless of the fact that I'm from north of the Mason-Dixon Line, I still wish to welcome all of you to <u>your workshop</u>.

Summary of Remarks by Anita Dean
Regional Activities Program Manager
Division of Hydroelectric Loan Resource Development, DOE

U.S. DEPARTMENT OF ENERGY
SMALL HYDRO PROGRAM

The Department of Energy was faced with the proposition of finding new and reliable sources of energy at the time of the oil embargo in 1973. The concept of small hydroelectric power is not new; in fact, we have reawakened a very old concept. The original intent of the program was for the government to step in, initiate generic efforts to reawaken the industry, and then step out. The plan of attack was to look at the feasibility of certain projects and see if they would, in fact, be suitable to utilize this renewable source of energy.

Like any other program, it had to be legislated, thoroughly regulated, implemented, and the outreach to the public well planned. I will elaborate on all of these points as we proceed to use this time as a "show-and-tell" type of keynoting procedure in which the various authorities, regulations and implementation procedures are shown on the viewgraphs. Additional comments will be made to highlight or emphasize certain points and comment on the effectiveness of the program.

PROGRAM HISTORY

- President's Energy Message, April 20, 1977
  - Directed Corps to Report on Hydropower Potential at Existing Dams
- Corps Report, July 20, 1977
  - Indicated Significant Potential, But Serious Constraints
- ERDA Initiated Work, 1977
  - Focused on Constraints
- First Demonstration Project Awarded, December 1978
- First Loan Awarded, April 1980
- First Demonstration Projects on Line, August 1980

The program history started originally with the President's Energy Message in 1977 with the specific thought to ascertain just how many hydropower facilities existed. Naturally the Corps of Engineers is the agency to have more firsthand information in this subject than anyone else. As you can see, things moved rather swiftly with the first demonstration projects being awarded in December, 1978, and the first loan being awarded in April, 1980.

The demonstration program located many of the barriers and problems that were to arise mainly on a state specific basis. Environmental barriers as well as delays in equipment delivery were the main problems affecting the scheduled completion of some projects.

AUTHORITIES

- Federal Non-Nuclear Research and Development Act of 1974
- Public Utility Regulatory Policies Act of 1978
  - Loans For Feasibility and Licensing Costs
  - State Incentives
- Crude Oil Windfall Profits Tax Act of 1980
  - 11% Energy Investment Tax Credit
  - Industrial Development Bonds
- Energy Security Act of 1980 (S. 932)
  - Study of Federal Programs, Policies

Once the attention is created, it is necessary to have further incentives. The first real incentive was in 1978 when the loans for feasibility and licensing costs were incorporated into the Public Utility Regulatory Policies Act. Further incentives came with the Crude Oil Windfall Profits Tax Act of 1980 which allowed an 11% energy investment-tax credit as well as the industrial development bonds. These two combined made it possible for both public and private developers to become very interested in this from the monetary concerns. This workshop's program will address these specific tax acts and regulations in more detail.

PROGRAM RATIONALE

- Hydropower ("Hydro") Is a Tangible, Proven Energy Source
- Small Hydro (SH):
  - Is Relatively Easily Developed
  - Can Be Developed Without Significant Federal Aid
  - Is a Significant "Renewable"
- SH Has Been Lying Dormant, But Changing Energy Economics Should Assist Reawakening
- Concept of SH Program Was for the Government to "Step In," Initiate Generic Efforts to Reawaken the Industry, and Then "Step Out"

As I've said before, hydropower is an old concept that needed to be revived. Actually, hydropower gave way to cheap oil and was supplemented by oil-fired plants because they were more dependable for a full, well-based electrical program and do not suffer the periods of off-peak power that we have visited upon us by weather. In other words, when we need the power in the winter and the summer, this is when the streams or the water flow is at its lowest. However, in order to avoid spending additional money to put in new nuclear and coal-fired plants and to take care of some of the off-peak load, small scale hydro has a definite part to play, and we felt that the government should initiate the efforts to reawaken this industry.

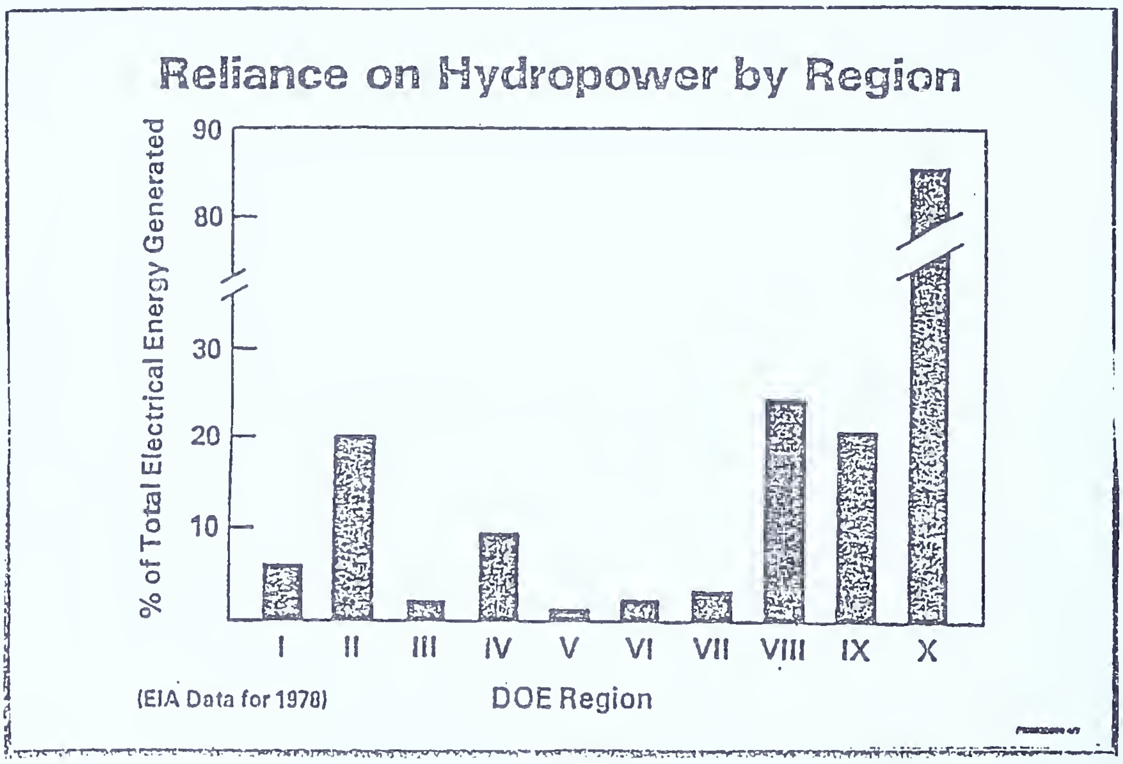
The present thinking favors the private sector for development of small scale hydroelectric sites. Federal aid is not a prime requisite for either private or public development. Our reason for preparing the financing books was to reflect this thinking.

GOALS AND OBJECTIVES

- The Basic Program Is To Reestablish A Vigorous SH Industry In The U.S.

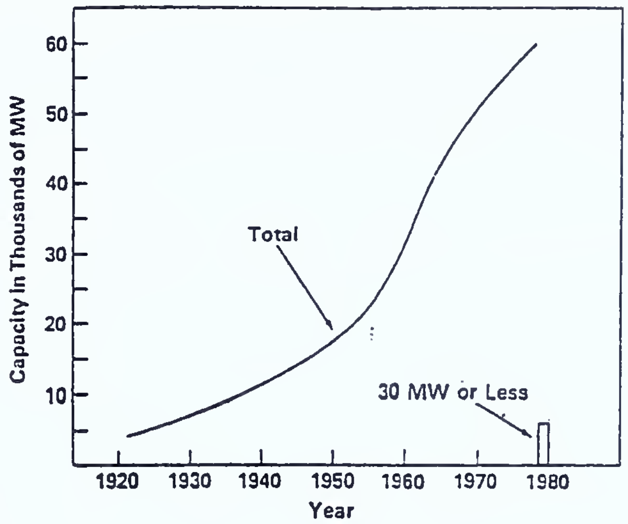
- Program Thrusts:
  - Create Public Awareness
  - Minimize Institutional, Environmental And Technical Barriers
  - Demonstrate Commerical Feasibility

The goals and objectives are stated here very simply: that the main thrust actually was to re-establish a vigorous small scale hydro industry in the United States. We were to go about this by creating the public awareness to minimize institutional, environmental and technical barriers. But, as most people know, we must actually demonstrate and prove the commerical feasibility.



For those of you who are not familiar with the Department of Energy, we are like many other Federal agencies; we are divided into 10 specific regions. This graph shows a reliance on hydropower by the different regions that make up the Department of Energy. As you can see, Region 10, which is the west coast and California area, has a great amount of reliance on hydropower. Region 3, the region which consists of Pennsylvania, Delaware, Maryland, Virginia, West Virginia and the District of Columbia, has very little hydropower developed in comparison to other areas. You can see the reason for stimulating interest, particularly in the Northeastern area where there is a great industrial demand for power.

Developed Hydropower Capacity in the U.S.



The thousands of megawatts of power are shown on the left and the year of development on the bottom line. As we can see, the total slowed down considerably in the 60's due to the relatively cheap price of oil, and in the 80's we had 30 megawatt or less developed hydropower capacity in the United States.

The retirement of hydroelectric facilities was not entirely energy pricing. At that time the utility rate was based on usage. The more you used, the cheaper the rate. Demand has changed this concept with "on peak" and "off peak" rates now being the basis of payment.

12-5-80

Conventional Hydroelectric Capacity by Class of Ownership, 1940-79

(millions of kilowatts)

Class of ownership	Installed capacity: year end 1940	1950	1960	1970	1979
Investor-owned utilities	8.5	9.7	13.4	16.3	16.6
Non-federal public utilities	1.1	1.5	4.4	11.9	13.2
Federal	1.7	6.5	14.6	23.0	32.8
Industrial	1.1	1.0	0.7	0.7	0.7
Total, all plants	12.4	18.7	33.1	51.9	63.3

Ref: DOE-FERC-0031, hydropower evaluation, Aug. 1979 and FERC data file January 1980

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In December, 1980, we have the class of ownership shown over nearly a 40-year period. As you will note, in 1940 we only had a total of all plants installed capacity of 12.4 millions of kilowatts. The significant thing about this ownership makes us aware of the fact that the industrial capacity has not been a deciding factor. In fact, the Federal, particularly in 1960 through 1979, installed capacity is the leader with the investor-owned utilities following in second place. The non-Federal public utilities will soon take over second place if their pace continues.

MAJOR PROGRAM ELEMENTS

- Demonstration Projects
- Technical Support and Development
- Institutional/Regulatory Reforms
- Regional and State Activities
- Loans

First in priority was, naturally, a demonstration project so the public could see and understand the principle and the quietness with which hydropower can be generated. We needed also to stimulate the technical support and development. In order to do this we started a program of technical assistance studies which were handled at the regional level to choose sites to receive a field visit by an engineer. Enough data could then be obtained to ascertain the proposed construction costs, the benefit/cost ratio and the annual yield. These are the primary concerns to locate a sponsor or to determine the feasible status of a site.

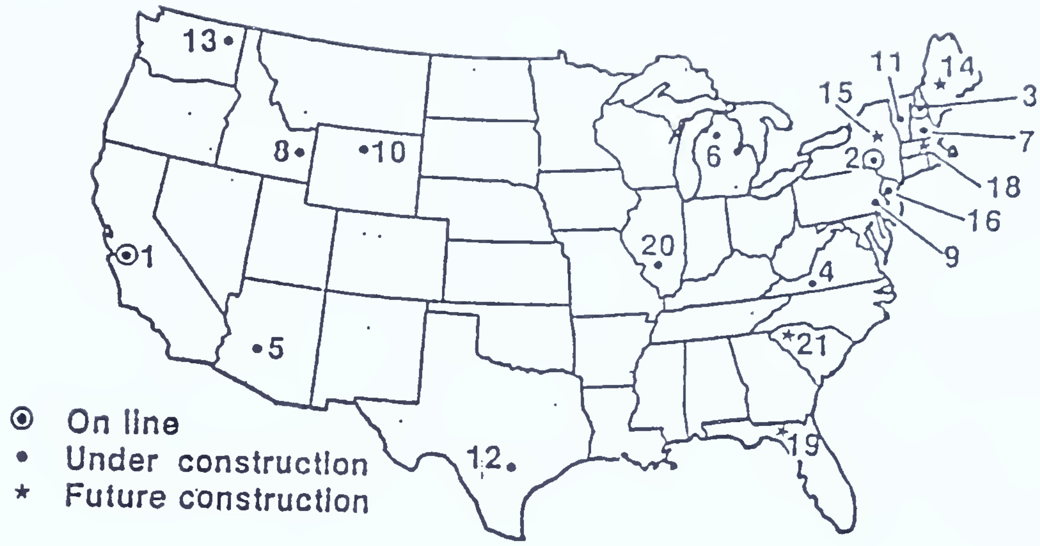
We had a few regulatory reforms that we wished to make: one was to extend the capacity from 15 megawatts to 30 megawatts. Our Regional and state activities were starting from square one. A lead Regional role was generally followed by strong state support.

DEMONSTRATION PROJECTS

PRINCIPAL OBJECTIVES

- To Stimulate Interest In Small Hydro
- To Get Some Projects Under Development Immediately
- Actual Case Studies Involving Economic, Technical, Environmental and Institutional Constraints
- To Stimulate U.S. Equipment Industry
- 20 Projects Selected

E HYDROELECTRIC
SOURCE DEVELOPMENT
S SUPPORTED 20
ALL HYDROPOWER
MONSTRATION
OJECTS



Our principal objective in order to stimulate interest in small scale hydro was to have some projects under development. To do this, and to stimulate the U.S. equipment and industry, we selected 20 different projects. Now these projects were not done at random. As we can see by the map, the 20 projects are widely scattered. Projects #4 and #9 are located in this Region. Number 4 is the plant on New River, Virginia, which is proceeding on schedule and is the site for tomorrow's field trip. Number 9 also is close to Philadelphia; it's the Flat Rock Dam.

	DOE FUNDS $ MILLIONS	TOTAL COST $ MILLIONS	UNDER CONSTR.	ON LINE	COMMENTS	MW
1. TURLOCK IRRIGATION DISTRICT, DROP #1, CA	.7	2.9	5/79	7/80	ON LINE	3.3
2. F.W.E. STAPENHORST, INC., GOODYEAR LAKE, NY	.2	1.6	7/79	7/80	ON LINE	1.3
3. BROWN-NEW HAMPSHIRE ANDROSCOGGIN RIVER, NH	1.0	4.3	12/79	1/81	ON LINE	2.8
4. RIEGEL TEXTILE, NEW RIVER, VA	.2	1.0	7/80	4/81	ON SCHEDULE	2.2
5. SALT RIVER PROJECT, SOUTH CANAL, AZ	.4	1.5	10/80	4/81	EQUIPMENT DELIVERY DELAY	1.4
6. ANTRIM COUNTY, ELK RIVER, MI	.2	.7	3/81	?	HAVE NOT YET SOLD BONDS	1.1
7. PUBLIC SERV. CO. OF NH, GARVIN FALLS, NH	.9	6.2	6/80	10/81		5.9
8. IDAHO FALLS	7.3	57.5	4/80	5/82	ON SCHEDULE	24
9. PENN. HYDRO DEV. CORP., FLAT ROCK DAM, PA	.9	6.2	8/81	1/82	ON SCHEDULE	3.5

	DOE FUNDS $ MILLIONS	TOTAL COST $ MILLIONS	UNDER CONSTR.	ON LINE	COMMENTS	MW
10. SHOSHONE IRRIGATION DIST., GARLAND CANAL, WY	.4	3.0	5/81	3/82		2.4
11. GREEN MT. POWER CO., WINOOSKI RIVER, VT	1.5	5.9	3/81	?	PROBLEM WITH MIN. INSTREAM FLOW RE-QUIREMENT	6.5
12. CITY OF GONZALES, DAM, TX	.3	2.0	5/81	7/82		1.1
13. CITY OF SPOKANE, UP RIVER, DAM WA	1.8	11.7	3/81	9/82		9.1
14. CENTRAL MAINE POWER, SHAWMUT DAME, ME	.9	5.8	11/81	10/82		3.4
15. NY STATE ELECTRIC & GAS, HUDSON RIVER,NY	2.5	18.0	3/81	12/82		16.8
16. CITY OF PATERSON, GREAT FALLS,NJ	1.3	8.8	10/80	10/83		7.5
17. DELETED						
18. BOOTT MILLS, PAW-TUCKET DAM, MA	2.2	28.0	6/81	12/83		15.0
19. CITY OF TALLAHASSEE, JACKSON BLUFF DAM,FL	1.8	11.7	7/82	2/84		8.8
20. CITY OF CARLYLE, CARYLE DAM, IL	1.2	7.8	1/82	4/84		8.8
21. BROAD RIVER ELECT. CO-OP, CHEROKEE DAM, SC	1.1	7.0	11/81	12/84		3.9

This slide may not be of particular interest to you except the comment that we were having a minimum flow requirement problem in Vermont. This is one of the things which came up later in our program in which minimum flow studies became of great importance. Our Idaho Field Operations Office has supplied the technical support and has been in charge of the development of our demonstration projects. There were many things which were lacking in hydropower and hydropower development due to the fact that it had not been a popular use of water in the United States. Indeed, most of the turbines being made in the United States were being shipped overseas until recently.

REGIONAL ACTIVITIES

- Promote Small Hydro
- Identify and Promote Specific Sites
- Regional Resource Inventories
- Review and Screen Loan Applications
- Provide Technical Assistance to Developers
- Conduct Workshops for Developers and States
- Encourage and Assist States to:
  - Initiate or Continue Hydro Programs
  - Promote Hydro Development
  - Identify and Streamline Licensing/Permitting Requirements
  - Provide Technical and Project Expediting Assistance for Developer

As you know, the purpose of Regions is to make a closer working relationship with the people, to be able to identify specific sites, to review and screen loan applications and provide technical assistance to developers. We have found that in most of our Regions this has worked very well for us as it provides someone they can turn to in their general vicinity who can assist them with the technical or general problems.

INSTITUTIONAL AND REGULATORY CONSTRAINTS

PRINCIPAL OBJECTIVES:

- TO IDENTIFY AND HELP MITIGATE:
  (1) INSTITUTIONAL BARRIERS (MOSTLY STATE-RELATED)
  (2) ENVIRONMENTAL CONSTRAINTS
- TO DEVELOP GUIDANCE AND EXPERTISE FOR SMALL HYDRO*
  *(SEE BIBLIOGRAPHY)

There were many constraints which were not immediately known at the beginning of the program. Many of the institutional barriers are mostly state related and vary from state to state. The environmental constraints naturally dealt with the migratory habits of fish and the necessity for fish ladders. Low flow studies became very important, and we found it necessary to develop guidance and expertise for the small scale hydro enthusiasts.

Specific studies were conducted by the Oak Ridge National Laboratory in their Environmental Sciences Division. A series of four volumes have been published entitled "Analysis of Environmental Issues Related to Small-Scale Hydroelectric Development." They deal with water level fluctuation, fish mortality resulting from turbine passage and similar concerns.

We have published the Micro Hydropower book; we have gone forward to other contractors, as I will get into later, to help support the program in other categories.

FEASIBILITY STUDY AND LICENSING LOANS

PRINCIPAL OBJECTIVES:

- TO HELP STIMULATE INTEREST IN SMALL HYDRO AND ENCOURAGE DEVELOPMENT
- TO ASSIST WITH FRONT-END COSTS

Many of you are familiar with our feasibility study and licensing loans with the principal objectives being, naturally, to stimulate and encourage the development of small scale hydro and assist in front-end costs. And I know many of you are keenly interested in what will happen to that program.

We must tell you that the Department of Energy's Feasibility and Licensing Loan Program is presently under review, and the future of the program has not yet been determined. It is anticipated that the Congress may reduce or defer funding provided to date, and the Department has not requested additional funding for the next fiscal year. The Applicant's Information Kits are being made available on request for the factual information provided therein, and applications are being accepted and processed by the Department. However, until further notice, applicants and potential applicants are being advised as to the uncertainty of receiving future DOE loans.

I'm not sure that is actually what all of you wish to hear, but the opinion of the present administration is that the small scale hydro program can be handled by the private sector. That is the reason for this type of workshop, to make known to you all the facts that are available.

PRINCIPAL CONTRACTORS

ENERGY LAW INSTITUTE

- GENERIC STUDIES, LEGAL & INSTITUTIONAL BARRIERS
- IMPLEMENTATION OF SECTION 210, PURPA
- TECHNICAL ASSISTANCE & WORKSHOPS

NATIONAL CONFERENCE OF STATE LEGISLATURES

- GENERIC & CASE STUDIES, LEGAL & INSTITUTIONAL BARRIERS
- TECHNICAL ASSISTANCE & WORKSHOPS

I mentioned our principal contractors; we have the Energy Law Institute, (ELI), and as you can see, their duties are listed. They have helped us considerably with the PURPA regulations which will be discussed in further detail. They have provided technical assistance workshops and have assisted in all the workshops we've had. Their representative will be participating in this one today. The ELI have compiled and edited the two blue-covereed books on private and public financing which, we hope, will be of assistance to you. Any comments on the content, format or accuracy of these volumes will be appreciated. The summary of the private financing which is a part of your handout will help to understand the complexity of the financial process.

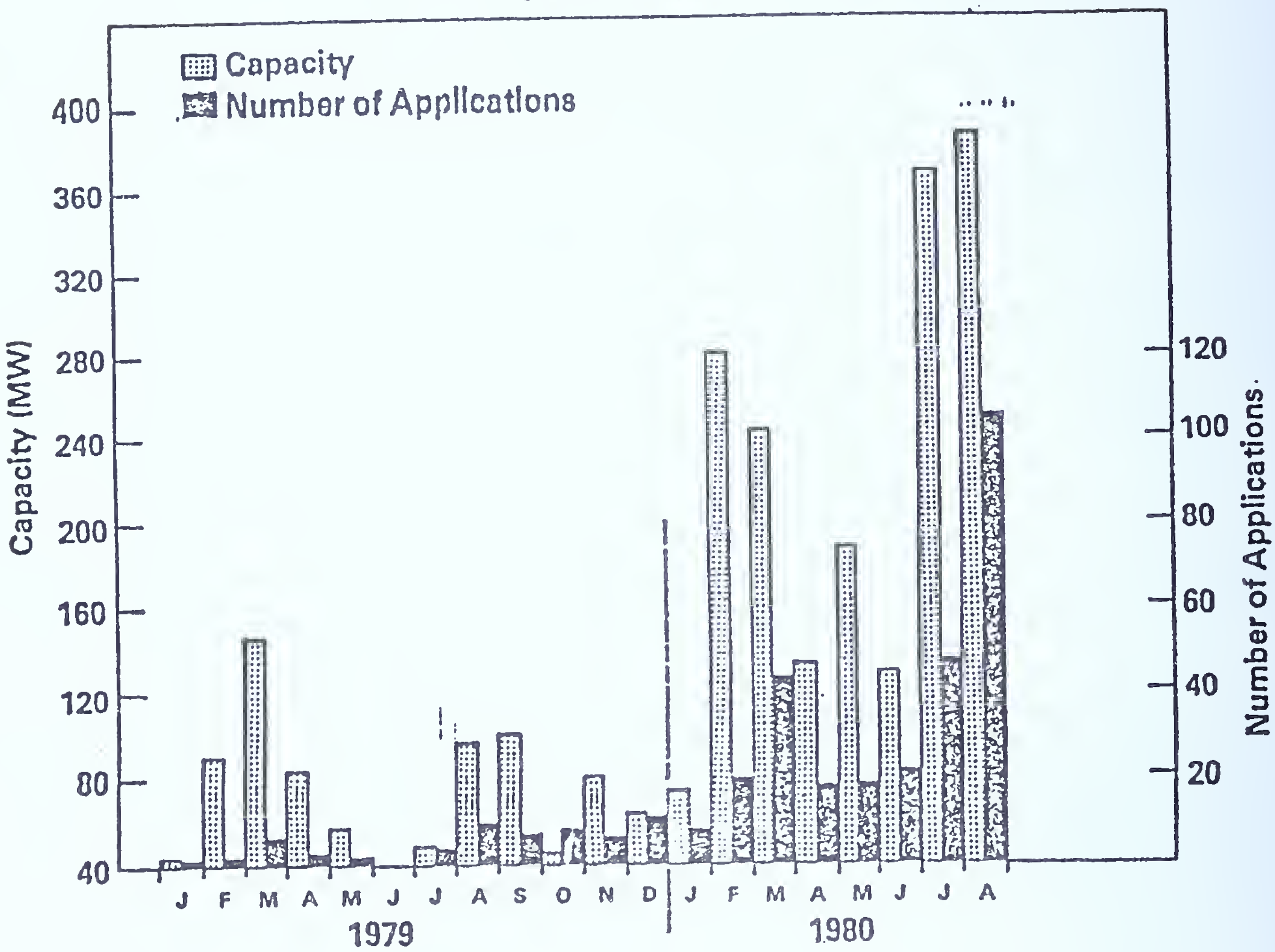
Also with them is a National Conference of State Legislators under contract to study the legal and institutional barriers on a state-specific basis. They also have a speaker here who will speak on the host state which in this case is Virginia.

PLANNED ACTIVITIES FOR FY 81

- 3 MORE DEMO PROJECTS ON LINE (TOTAL OF 5)
- 65 PROJECTS TO RECEIVE TECHNICAL ASSISTANCE
- 30 WORKSHOPS CONDUCTED FOR PUCs, STATE LEGISLATURES, STATE HYDRO PERSONNEL, AND DEVELOPERS
- MINIMUM STREAMFLOW REQUIREMENTS RESEARCH

The activities for fiscal year 1981 show a total of five demo projects on line (as I mentioned, one can be viewed tomorrow); 65 projects have received technical assistance; 30 workshops have been conducted of which this is one. We are striving to bring to you the state of the art information on the development of small scale hydro. We also are engaging in minimum stream flow requirement research.

Preliminary Permit Applications
(≤30 MW)



The permitting process through the Federal Energy Regulatory Commission has had a very interesting past and defines the unexpected upturn in applications. As you will note, in 1979 the number of applications over the year were not that enormous; but you will notice here, both the capacity (which is shown with the dotted bars) and the number of applications have quadrupled, if we look at the August applications compared to August of the preceding year. Our representative from FERC will fill us in; I'm certain that this has been outdated and that the current number of preliminary permits has reached staggering proportions.

PRELIMINARY PERMITS PENDING AND IN EFFECT
AS OF SEPTEMBER 30, 1980

TOTAL INSTALLED CAPACITY BY SITE

SIZE CATEGORY		CAPACITY MW
OVER 100 MW		2,183
30 MW TO 100 MW		2,017
100 KW TO 30 MW		3,105
	TOTAL MW	7,305

REF: FERC APPLICATIONS LISTING, TABLES 2 AND 3

As we look further into the permitting, we find that the listings as of September 30, 1980, in the category defined as small scale hydro, between the minimum of 100 kilowatts and the 30 megawatts, we have 3,105 megawatt capacity. It is not the large capacity or the "on peak" installation that are making the anticipated savings, but the small scale hydro that is paving the way.

In closing, our Idaho Field Office naturally has several studies that have been evaluated that are recommended for funding, and appropriate letters have been sent to the applicants saying that the future availability of funding will determine whether they receive funds for these. We have been well-pleased with the amount of response we had to the program. The workshops and other outreach activities such as these books on financial management, this workshop, and other information disseminated periodically, we hope have been of some assistance to you would-be applicants and hydro enthusiasts.

As I mentioned in the beginning of my time frame, the idea of the Federal Government was to stimulate and to start the program and then step out. As of this moment we are not sure when we will really be stepping out, but we're glad to experience this enthusiasm and attendance on this beautiful campus.

PENNSYLVANIA
SMALL-SCALE HYDROELECTRIC DEVELOPMENT
Legislative Issues and Alternatives
(Prepared by NCSL)

Note: This summarizes the issues and legislative alternatives identified in the report entitled, Pennsylvania Small-Scale Hydroelectric Policy Report: Legislative Issues and Alternatives (January 1981)

Issue I - To modify the Pennsylvania Scenic Rivers Act (PSRA) to allow for consideration of the potential for hydropower development prior to PSRA classification.

Issue II - To provide a mechanism for disssemination of information regarding small-scale hydroelectric development.

Issue III - To exempt hydroelectric projects from the requirements of the Pennsylvania Municipal Planning Code.

Issue IV - To improve the marketing conditions for small-scale hydroelectric facilities by municipalities.

Issue V - To encourage the development of small-scale hydroelectric projects at the state level through the Public Utilitites Commission.

Issue VI - To provide financial incentives to small-scale hydroelectric projects by allowing in lieu of taxation or by temporarily exempting sites from property taxation.

Issue VII - To provide financial incentives to small-scale hydroelectric projects by exempting all of these projects from the Utilities Gross Receipts Tax.

Issue VIII - To facilitate private small-scale hydro project financing by providing private hydroelectric projects with access to tax exempt financing through Pennsylvania Industrial Development Authorities.

Issue IX - To encourage the development of small-scale hydro projects by utilizing a state renewable energy development fund or some other state funding to provide financial assistance to private small-scale hydro developers.

For additional information, see the following NCSL publications:

1) An Introduction to Small-Scale Hydroelectric Power in the State of Pennsylvania (January 1980);
2) Pennsylvania Small-Scale Hydroelectric Policy Report: Preliminary Issues and Options (May 1980);
3) Pennsylvania Small-Scale Hydroelectric Policy Report: Legislative Issues and Alternatives (January 1981); and
4) A Legislator's Guide to Small-Scale Hydroelectric Development (April 1980)

VIRGINIA LEGAL BARRIERS - HOST STATE

William Ferguson

Mr. Ferguson graduated from the University of Colorado, Law School as a Juris Doctor. He also holds a Bachelor of Arts degree from Yale University.

Presently he is staff associate on the Energy Program of the National Conference of State Legislatures (NCSL). He is a specialist in small scale hydro where he stimulates and assists state legislative action to encourage its efficient development. The NCSL is associated by contractural arrangements with the Energy Law Institute of Franklin Pierce Law Center in these functions.

Prior to this employment he was a partner in the law firm of Bernard & Ferguson of Boulder, CO., and served as a computer systems analysist for the Stanford Research Institute of Menlo, Park, CA.

Following his presentation at V.P.I. is a summary of issues discussed in his Pennsylvania presentation.

It's nice to see all this interest in hydro development in Virginia. I'd like to tell you about our organization, the work that we will be doing in the state of Virginia, how we go about it, and give you a brief overview of our current analysis of state statutes regarding hydropower in Virginia. I will caveat my talk with the fact that we are just starting our Virginia work. We've done an initial statute survey and that will be the basis of my discussion of the Virginia legal environment.

As Ed mentioned, I work for the National Conference of State Legislatures (NCSL). This is a national organization with headquarters in Denver, Colorado, and a secondary office in Washington, D.C. NCSL assists state legislatures in the development of new statutory changes in whatever subject matter is interesting to that particular legislature. We have about 100 people in the Denver office with different areas of expertise; I happen to be in the small scale hydro program. Our Washington office keeps us apprised of Federal activities that will affect the states and takes the view of state legislatures to Capitol Hill.

The NCSL small hydro program works with a group called the Energy Law Institute, Concord, New Hampshire. The speaker after me is Bill Wilson. He has been working specifically on this question of state legislation regarding small scale hydro for the past several years, and our program -- NCSL and ELI -- have worked jointly in the development of legislation in a number of states across the country. This program of technical assistance has the goal of providing legal and economic analyses of state interaction with small scale hydro development, with the possibility of statutory amendments where appropriate.

Technical assistance generally has five stages: The first stage is research of the statutes and the actual field research of what developers are finding; the second is work with a committee on identifying the state issues which seem most pressing in that particular state; the third stage is selecting options which can remedy these problems and are acceptable to the major actors in the field, which are usually developers, electric utilities, state agencies, and financing institutions; fourth, upon request we will work on drafting legislation to accomplish this purpose; and fifth, we have follow-up services -- working with agencies if that's necessary, testifying on behalf of the bill if that's necessary. These are the steps that are involved.

I prefer to look at this area as the legal environment as opposed to legal barriers. It's a complicated web, but usually there is nothing that is particularly prohibitive. Rather, the environment may be inconvenient, time-consuming, and perhaps expensive. This is where we look to change state action towards hydropower and make it more economical and less time-consuming.

I'd like to mention some of the other states that we've worked with in the past and some of the things that have happened: In North Carolina, our program worked on development of a new statute setting up a mechanism for determining long-term rates for small hydro facilities, with implementation by the North Carolina Utilities Commission. The developers are pleased because they are able to get consideration from the utility of the long-term benefits and set up a much more stable revenue stream than was previously possible. In Alaska we worked on development of a statute authorizing the Alaska Power Authority to engage in hydropower development and worked on setting up the parameters of its financing mechanism. Legislation which we proposed in New Hampshire and Montana has been enacted into law. In addition to these four states where we have developed new statutory approaches, we have provided technical assistance to another ten states.

In the course of working with a state, we try to examine all facets of state interaction with small scale hydro. Generally, this interaction can be analyzed using the following framework: water law, public utility regulation, environmental regulation, taxation, incentives/obstacles to private development, and incentives/obstacles to public development.

Turning to the Virginia legal environment, I'd like to discuss water law first. Virginia uses the riparian water system, by which a developer acquires a right to use water based upon owning the land under or adjacent to the waterway.[1] Land (and hence, water rights) may be acquired by lease, purchase, or condemnation. Most political subdivisions (such as municipalities) and public service corporations (such as most electric utilities) have the right of condemnation. Additionally, entities which hold a Federal Energy Regulatory Commission (FERC, formerly Federal Power Commission) license can use Federal condemnation rights.

There has been some discussion in Virginia regarding changing from a riparian system to an appropriation system. An appropriation system, commonly used in Western states, allocates water by permit rather than land ownership. However, at this time, Virginia remains with a riparian system.

The next area I'd like to discuss is statement involvement in public utility and environmental regulation. An agency involved in both subjects is the State Corporations Commission (SCC). It has authority to regulate all aspects of electric utility operations[2] and also regulates construction and reconstruction of dams.[3] However, recent changes in the Virginia statutes exempt most small scale hydro sites from both areas of regulations.[4] These exemptions will cover most sites in the state.

A facility must meet the following criteria to qualify for the exemptions. It must have a capacity of 20 megawatts or less, be a "qualifying facility" under federal law (discussed further below), and sell electricity at retail to no more than 5 end-users (none of which may be residential customers).[5]

The federal law mentioned in the preceding paragraph is the Public Utility Regulatory Policies Act of 1978 (PURPA).[6]

For purposes of this discussion, PURPA defines a "qualifying facility" as a facility which has a capacity of 80 megawatts or less, uses renewable resources as a fuel source, and is owned by a person not primarily engaged in the generation or sale of electricity (other than electricity from the qualifying facility). Meeting these federal requirements is necessary to achieve the state exemptions discussed above.

Additionally, status as a "qualifying facility" authorizes the state public utility commission, which is the SCC in Virginia, to offer two federal incentives. Electric utilities are required to interconnect with a "qualifying facility" and to purchase the output from a "qualifying facility" at an "avoided cost" rate. This is the cost a utility would incur to generate or purchase that amount of power. It includes compensation for both the cost of energy for that power and the cost of system capacity for that power.[7]

In addition to the SCC, jurisdiction over small hydro is asserted by several other state and local agencies. The State Water Control Board is charged with protecting the waters of the state;[8] it's mainly concerned with pollution control, but is also concerned with the development of watersheds in an orderly fashion and administration of the Flood Damage Reduction Act. There's the Department of Conservation and Economic Development.[9] This department protects state land throughout the state and has a number of divisions including Division of Forestry, Division of Mineral Resources, Division of Parks and the Virginia State Travel Service. The Commission of Outdoor Recreation administers the Scenic Rivers Act.[10] To be classified as "scenic", a river must be recommended by the Commission and approved by the legislature and governor. Certainly a developer would want to check to ensure that a river was not designated "scenic" either under Federal law or under State law before commencing development.

There's the Council on the Environment,[11] which administers the Virginia Environmental Quality Act. This Council is broken into a number of subgroups which include the State Air Pollution Control Board, the Board of Conservation and Economic Development, which I mentioned, the State Health Department, Marine Resources Commission, Soil and Water Conservation Commission, and the State Water Control Board. They have set up a procedure whereby if you need permits from several of these agencies, you can submit a single unified application. Additionally, there's the Commission of Game and Inland Fisheries,[12] which, needless to say, is supposed to protect the fish resources of the state. There's a Virginia Historical Landmarks Commission,[13] which would come into play if a historic landmark was present on the site; the Virginia Antiquities Act,[14] if there are antiquities present. The Virginia Endangered Species Act[15] which will probably prohibit development in a habitat where endangered species exist. In addition to all this, there are local planning commissions who must approve development and local zoning commissions that must approve development if there's a comprehensive zoning plan in that area.[16]

I earlier mentioned the Soil and Water Conservation Commission,[17] which ensures protection of the soil both under State and Federal law. Entities known as Watershed Improvement Districts[18] can be set up within Soil and Water Commission

Districts to ensure development of those particular areas. There's a Wetlands Act[19] in the state that must be complied with if you are developing in a wetland area. Agricultural and Forestal Districts[20] can be created. Municipal corporations, electric authorities, and counties can get involved in terms of development. Also, there are sanitation districts and drainage project districts which also can become involved. Finally, there are three interstate compacts which will relate to hydro on certain rivers, the Potomac River Basin Compact, the Ohio River Valley Water Santitation Commission, and the Ohio River Basin Commission.[21]

Simply because there's a lot of permits doesn't necessarily mean it's difficult to comply. It's really a question of how easy is it to get the information to an agency and get an answer? One of the things for you to do as developers is to informally contact these agencies and commissions as early in your project as you can. Before you've got a lot of money invested in a definite plan, find out if they are going to be interested in your project; let them know generally what your project will do, and see their reaction. Informal negotiations at the beginning seem to be a very good way of eliminating big problems and big expenses down the line.

I want to discuss the subject of taxes in Virginia and the taxes which affect small hydro. The first tax I'd like to examine is the Real Property Tax.[22] This is very important in small hydro development. It's likely to be the second largest expense over the life of the facility. The largest expense is usually debt service; the second largest is usually payment of the Real Property Tax. Part of the reason for this is small hydro, generally speaking, costs more to install than a coal power plant per kilowatt. So you tie up more capital right at the beginning with small hydro. Because of this extra capital cost the Real Property Tax system can effectively discriminate against small hydro over the life of the project because you always have more capital cost per kilowatt than a coal power plant. Virginia has just passed a statute allowing a small scale hydro developer to negotiate his/her property tax with the local taxing authority.

I'll run through some of the other taxes quickly. Personal Property Tax can apply on machinery and tools used in the facility.[23] Corporate Income Tax of 6% is due on ordinarily taxable income.[24] The Franchise Tax can range between \$20 and \$20,000 depending on the amount of stock outstanding. Public service corporations have a different tax structure.[25] The state assesses property across the entire state and taxes gross receipts at a rate of 1-1/8% of the first \$100,000 and 3-1/2% of amounts over \$100,000. This tax is then redistributed to the local taxing entities.

The final topic I'd like to discuss is public and quasi-public development. We're looking at what kind of mechanisms exist for counties, municipalities and other political subdivisions to enter into small hydro projects. First of all, there's presently no state entity authorized to participate in small hydro. There are constitutional provisions preventing the state from becoming interested or party to any internal improvement.[26] However, in 1959 the Supreme Court held that ownership and control of port facilities was a governmental function in that it provided for the welfare and the prosperity of the people.[27] This might imply that small scale hydro or renewable energy development would also be considered appropriate for use of state funds. However, at the present time there is no state entity with sufficient statutory authority.

I'd like to briefly discuss types of bonding mechanisms. The state, municipalities and counties all can engage in three different types of bonding. There's general obligation bonds that pledge the full faith and credit of the political entity (and that basically means the taxing power of that entity) to repay those bonds. There are constitutional and statutory limits on the maximum amount of these bonds. There's revenue bonds which are not guaranteed by the taxing power of the authority; rather, they are guaranteed by the revenue of the project. Finally, there's a hybrid called a double-barreled bond which is a revenue bond backed by the full faith and credit. The state, municipalities and the counties can do all three kinds of bonding. This would be how they could raise money for hydro.

Municipalities are specifically authorized to construct their own municipal electric facilities.[28] They can acquire property by purchase or condemnation. There are certain limits on condemnation, such as, they cannot condemn a utility owned by another political subdivision; they cannot acquire a facility owned by a public service corporation without special approval; and other specific instances where condemnation is not allowed. There's a condemnation section in the statute which sets forth the rules. However, municipalities can engage in development of small scale hydro, both within and outside their municipal district. One thing that is not clear from the statutes is whether such a facility can engage in wholesale sales. That is, could the municipality develop the site and sell it to the local investor-owned utility. It's clear that they can sell it to the city, itself, and to the inhabitants of the city, but it's not clear whether they can sell it outside to an investor or utility.

Another avenue for public development is where municipalities have joined together to form an electric authority pursuant to the Electric Authorities Act.[29] This electric authority is a conglomeration of several municipalities joined together for the purposes of developing electric facilities. One of the things that is interesting about electric authorities and could provide some benefit to municipalities is that electric authorities specifically are allowed to engage in wholesale sales and are specifically prohibited from retail sales. If there is insufficient authority for municipal wholesale sales this could be an alternative avenue. Electric authorities do not have the full range of bonding powers that a municipality has; they can only engage in revenue bonding. Counties are basically just like municipalities -- they've got the full range of bonding, they can set up electric plants; it's unclear whether they can engage in wholesale sales.[30]

Finally, it does appear that it may be possible to give assistance to private developers through industrial development authorities pursuant to the Industrial Development and Revenue Bond Act.[31] Basically, these are entities which are allowed under Federal law to issue tax-exempt bonds, loan these proceeds to particular qualifying projects, and thus give a private developer access to tax-exempt financing. There are particular criteria that must be met in the issuance of the bond to maintain the tax-exempt status, and I suspect that Bill Wilson will probably cover that.

I will be around today and tomorrow. Please catch me if you have any questions. Thank you.

FOOTNOTES

1 Va. Code Sec. 62.1-10 et. seq.

2 Va. Code Sec. 12.1-12 et. seq.

3 Va. Code Sec. 62.1-80 et. seq.

4 Chap. 557; Chap. 385 - Laws of 1981.

5 Id.

6 Public Law 95-617.

7 Id.

8 Va. Code Sec. 62.1-44.36; Sec. 62.1-104.1 et. seq.

9 Va. Code Sec. 10-8.1 et. seq.

10 Va. Code Sec. 10-167.

11 Va. Code Sec. 10-177.

12 Va. Code Sec. 29-1L.

13 Va. Code Sec. 10-150.5B.

14 Id.

15 Va. Code Sec. 29-232 et. seq.

16 Va. Code Sec. 15.1-427; 15.1-446.

17 Va. Code Sec. 21.6.

FOOTNOTES - 2

18
Va. Code Sec. 21-112.1.

19
Va. Code Sec. 62.1-13.1.

20
Va. Code Sec. 15.1-1511.

21
Va. Code Sec. 62.1-69; 62.1-1-70; and 62.1-1-79.1.

22
Va. Code Sec. 58-9; 58-602; and 58-758.

23
Va. Code Sec. 58-412; 58-831.

24
Va. Code Sec. 58-151.03 et. seq.

25
Va. Code Sec. 58-603; 58-606; and 58-661.

26
Va. Const. Art. X, Sec. 10.

27
Harrison v. Day, 200 Va. 750, 107 S.E. 2d 585 (1959).

28
Va. Code Sec. 15.1-877.

29
Va. Code Sec. 15.1-1603 et. seq.

30
Va. Code Sec. 15.1-185.

31
Va. Code Sec. 15.1-1371 et. seq.

FINANCE PLANNING BY THE BOOK

Bill Wilson
Energy Law Institute
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Bill Wilson is an attorney and Director of Legislative Assistance at the Energy Law Institute of the Franklin Pierce Law Center. While at the Institute, Mr. Wilson has specialized in regulatory law, taxation and financing hydropower development. Mr. Wilson has provided direct advice to numerous state legislatures on opportunity to encourage hydropower and other renewable energy project development and drafted legislation to accomplish that end in many of those states. Mr. Wilson has also assisted several renewable energy project developers in their development efforts. Mr. Wilson is a graduate of Washington College and completed his legal education at the University of Virginia and the Franklin Pierce Center.

It's a pleasure to be here today for a couple of personal reasons, among others. As a matter of fact, I started out my legal career a long time ago by attending the University of Virginia Law School in Charlottesville, and I enjoyed being in this state very much during that period of time. Additionally, I first learned to fly in this area. I enjoyed flying over your mountains on numerous occasions, and the flight in here last night with Air Virginia reminded me of some of the intersting perils of doing that, as a matter of fact.

The Energy Law Institute has been involved in analyzing legal, institutional opportunities and problems associated with the development of a number of renewable energy sources for about the last three years. I've been with the organization for much of that time, and my primary duties with the Institute

have included extensive involvement in small scale hydro, particularly in trying to devise strategies for improving the financial viability of the resource.

I would like to make a few observations about the genesis of the documents that you have. We discovered early in our efforts to provide both technical assistance to state legislatures and advice to developers in the development of small scale hydro that the financing and power marketing of this source of energy was absolutely one of the most critical -- if not the most critical -- aspects of getting the resource on line. As a consequence of that, we ended up spending a lot of time in research, exclusively devoted to learning about how these things could be improved and, of course, we learned some things which we think will be useful to those of you who are just undertaking to develop one of these projects. We decided early in our contract with DOE, with Anita's help, to break the manuals into three parts. Two in particular we thought were absolutely critical -- the public manual and the private manual. And we did that primarily because the financing of public and private hydro facilities entail substantially different climates for development and present a different set of financial variables. Certain economic factors remain constant, but the financial opportunities vary considerably depending on whether or not you're talking about a privately-owned project or a publicly-owned project.

While we had at one time hoped to come up with a very short private manual, we soon discovered that the complexities of what we wanted to talk about, which we thought really deserved some careful attention and at least presented some need for description, were such that we really couldn't get the manual much shorter than it turned out to be. And I think you can see from the private manual, we ended up with about 90-some pages. We had originally hoped for about 25. So, as a result, Anita asked us to put together somewhat of a summary of the private manual, which you have in your handouts. It is our best effort at trying to summarize this mass of information that is contained in the private manual. Because many of the items that are discussed in the private manual bear somewhat on financing of public projects and not so much the other way around, because there's a lot more chartered territory in the financing of public projects for this resource, and because we didn't have to get into the tax complexities for the development of the public resource, the public manual is much shorter and, consequently, doesn't have a summary.

With all that in mind, what I'd like to do now is to take you briefly through the two documents, try to point out some of their most salient features and indicate what we feel are some of the more important substantive points that are made in those documents. Then at the end I would like to give you an opportunity to ask some questions. I do know that you will be receiving some additional counseling in regard to the private and public financing of small scale hydro projects on the program tomorrow. Consequently I would like to try not to be redundant. I have heard the other speakers' presentations at least once now, and unless they change too much on me I think I can achieve this with some success.

I'd like to start with the private manual because, as I said, it does involve some considerations that are more complex than those we encountered in the financing of the public facilities. We start off with a discussion of what should be, we think, one of the most important documents or activities that a private developer can undertake when he tries to decide how to finance one of these projects: the creation of a business plan. Consequently, in Chapter 2,

we go into a discussion of why we think the plan is important, what we think are the major components of that plan, and what are some of the questions that should be addressed in the course of developing that plan. In that chapter we stress what we call the simultaneity of many of the financial decisions that a private developer -- and of course this applies to a public entity as well, but I'm going to stick with the private references for this manual -- the decisions that a developer will have to make in the course of actually getting his project financed. All we mean to suggest by that is that there are just a lot of things happening at the same time.

If you want to turn to page 5, you will see that we throw in a hypothetical decision schedule to bring that point home a bit. For example, you are going to be involved in considerations of licensing; at the same time you're going to be involved in trying to assess the economic viability of your project. You will have to plan for a variety of different kinds of expenses, and it's going to be difficult to predict in advance exactly when they will occur; but, nonetheless, you have to have some rought idea of how you're going to deal with those at different phases of the project. You are going to have increasing opportunity to obtain more sophisticated and more complete information as you get further and further involved in the project, and that will change a lot of your initial assumptions. For example, many of your assumptions about what is available in terms of tax benefits in the project may change substantially as you get more refined in your analysis. Additionally, your initial determinations of what you can expect in the way of power sales, prices and, consequently, revenues in the project may change a lot as you get down to the final planning. We're trying to suggest by this chart, and the point which I'm on the verge of belaboring, I suppose, is that you have to be flexible and recognize the fact that from the starting point you've got to manage a lot of different tasks. In addition, you will be constantly refining your analysis of those tasks as you go along.

We next get into a discussion of actually what should be the suggested content of the plan, and that begins of page 4. Basically, what we have here is an outline of what we think are the various stages of developing a plan and what we think some of the important questions are in each one of those stages. We have a stage one, which is an initial screening stage. During this stage you've got to get rough estimates or best information available, bearing in mind the need to keep your costs down as much as possible on design costs, licensing costs, engineering costs, all the other costs you can anticipate being associated with in the development of the project. Of course, you certainly want to be sure you have nailed down your site in one way or another. But I'm not going to get into FERC licensing since Don Giampaoli will take care of that later this afternoon. Nevertheless, you should note that it is important to decide at this point whether or not you want to go in exemption, whether or not you want to go with the preliminary permit and reserve the site, or whether or not you want to proceed directly to license. There are pro's and con's of proceeding with each approach. But one thing you do want to be sure of, because of the Federal Power Act, is to reserve your right to develop that site. That's going to require some affirmative action on your part for almost all the rivers that we can think of; navigability is very broadly defined under the Federal Power Act. You also want to have a rough evaluation even at the initial stage of what kind of power sales price you can expect. Now that may be difficult, it may be easy. It will depend largely on where your public utility commission stands in its PURPA Title II implementation.

If, for instance, they've gotten a final order out, as we have in New Hampshire, then you're going to have a very good indication of at least one of the parameters for the power sales contract negotiations. You're going to know what "avoided cost" is for the utilities that have been covered by that order. You're going to know under what terms and conditions you can actually obtain that rate. Depending upon the commission, that is, on how they interpret their obligations under PURPA, you may or may not have access to a commission-mandated long-term rate structure of some kind. Again, depending on parallel considerations of state public utility law, if you are in a state like North Carolina or Maine or, hopefully soon, Montana, then you will have a state requirement that the commission make available long-term rates. This would of course give you fairly accurate information on what rates to expect for power over some definite extended period.

You may have some information at this stage on what the utility's bargaining history has been in this area. Ed mentioned, for instance, PP&L's posted rate as 6¢. If you've got a utility that's actually on its own initiative posted a tariff, then you know that that's their perspective on things. You don't necessarily have to assume that it's going to be the bottom line, but you should have some indication of what direction they're going.

You, as a developer, should also have a very good analysis in the early stages of what your net worth is or what resources you're willing to commit to this project. That's very important because it has a substantial impact on the kind of business structure that is used to bring the project on line. You need to consider, for instance, your tax bracket, obviously; the extent to which you can use whatever tax benefits, personally that is, the project may generate. If you're a corporation, of course, you make the same kind of analysis; you need to decide, for instance, how you're going to deal with the upfront capital expenses, how you're going to deal with the negative cash flow for this project in the early stages because there is some lead time involved. The period of time between your initial investments and your actual return in the way of project revenues can be fairly substantial. And of course a lot of that is dependent on a lot of external variables that you've got to try to assess as best you can.

In addition to the actual licensing process, you should know early on the susceptibility of the project to hostile local community response, or environmental response or any other activities that might make their way into a formal intervention or otherwise impede the process. You need to take a close look at the environmental implications of your site for that reason, because obviously that translates into delay and substantial cost. You also at this point should have some rough idea, once you've made these preliminary assessments about some of the variables that are so critical to this decision, what kind of a development strategy you're going to pursue. By that I mean, what kind of business structure do you think is appropriate for you? We get into this a bit more; particularly with regard to some of the factors that impact on the decision on which structure to use, but essentially I'm talking about the differences between a corporate form, a partnership and, a limited partnership. Of course you could be a sole proprietor also, and many developers, in fact, are doing that. But what you want to do is, considering the best information you have at the time, determine what looks like the most economical way of proceeding. This should take you into what we describe as phase 2 of the development of a plan, and that's actually undertaking to set out the tasks that are going to be involved in managing the development of the project.

Here you need to take into consideration where are you going to get the expertise to accomplish all the necessary tasks involved: Are you going to engage in a contract with a developing firm who has expertise in its small scale hydro development or related development? Are you going to undertake to learn or perhaps expand your existing knowledge in this area and do the project exclusively on your own? In making these kinds of decisions, we think it's absolutely critical that you as a site owner, or you as an engineering firm advising the site owners, undertake a very critical assessment of what your own capabilities are and how you plan to proceed. It is costly to develop the skills involved in bringing the project on line, and you need to assess for yourself whether or not, based on your judgement, it is more economical for you to actually acquire outside expertise and under what circumstances. There are lots of options available.

Now is the time to firm up all your previous estimates. You should have very good numbers at this point. You should get involved in the negotiation and execution of your power sales arrangements or contract -- if that is your decision. There is no hard and fast requirement that you get a power sales contract. It may be an essential part of your financing under certain circumstances. However, there are options for avoiding it. Its essential value to you is one of security. It means that you have some commitment over a substantial period of time to obtain power at a certain price, or at least in most power contracts there would be a formula under which you can estimate the opportunities for power sales revenues over the term of that contract. Essentially, what you're doing when you negotiate a power contract is trading off some of the opportunity for return in return for that security. It is essentially a question of risk/return tradeoff.

In deciding how to go about your power contract negotiations, you also need to decide again where you're going to get the expertise to undertake this. The power companies already have the expertise in house; they have been doing this kind of thing for years; maybe not with small power producers, but certainly they've been negotiating power sales contracts for years. You may not have ever done that. They have unique access to economic assistance that you may not possess. They also have a stable of well-trained regulatory lawyers, if it turns out that you need actually appear before the commission for some reason. As a consequence, you need to take a close look at your needs at that point in time and decide how it is you are actually going to go about securing the power sales arrangements.

You're going to be doing the things I've mentioned and others simultaneously. For example, you can't really complete your financial negotiations until you've completed at least the bare bones of your power contract negotiations because you're not going to be able to get the necessary commitments. Similarly, you're certainly not going to be able to complete your financial arrangements until you have obtained all the necessary regulatory approvals. I know of very few lenders who are willing to give you carte blanche if you haven't obtained the necessary license and exemption.

Just a quick point here on exemption, from the lender's perspective it's a little bit of an unknown. It's a new thing. They have some reservations. I'm not going to say this is absolute, it really depends on the lenders, but many of them who haven't seen a history of this -- and there's only a limited history, the regulations were just completed a short time ago -- many of them will have reservations about commiting financing until all the conditions that need to be attached to the exemption have been completed. Particularly things like minimum flow conditions that might come out of Fish and Wildlife or at

the state equivalent, and I think you can all understand why that might be true. Things like conditions of minimum flow can drastically alter the project economics. So they may have some reservations about the exemption, and you may have to try to get the best commitment on conditions you can at that time. I think you can expect that some lenders will be a little bit more willing to take the slight risk that may be entailed by this situation than others.

To structure the financing of the project you need to obviously consider the project's financing needs over the various periods of its development. You need upfront funds which I've already mentioned. Those have to come from either your own worth or some outside investment source. The external government assistance in this area has been severely curtailed, as you well know, and so the prospect for additional funding in this area is not particularly good. Thus, if you have not already funded your feasibility study through the loan program or made some substantial progress in this direction, you may have to seek other sources. You also need to make the arrangements for your construction loan which is what's going to cover you during the zero revenue period of your project? Largely speaking, the construction loan conditions will be determined on the basis of whatever long-term takeout arrangements have been secured, so you will need to arrange the long-term takeout in most cases prior to actually finalizing the conditions for the construction loan.

We go on in stage 2 to discuss some of the other factors that need to be considered at this stage. I think it suffices to say at this point that there are a number of additional factors, and you need to get the best information available.

The final stage is really not so much of a stage, it's a reference to some other requirements that you will have in conjunction with your business plan; we call them supporting documents. It's essentially our attempt to collect some of the items of support, that you need to bring with you for your financial negotiations. Essentially it's the documentary evidence of your progress in the various areas that I've mentioned and some others.

The next major section of the document goes into a discussion of business organizational options. We are talking about the three forms that I've mentioned earlier here. If you plan to make substantial use of the tax benefits, and you as the site owner cannot use them personally, then you're going to need some kind of what we call a tax flow-through device in order to accomplish that objective. The limited partnership is probably the easiest to manage of the two that we suggest as being available. A Subchapter S corporation can be used for that purpose; however, it has more limitations. One of those limitations is the fact that the I.R.S. recently had attached a little more scrutiny to the details of ensuring that a Subchapter S corporation is treated in an appropriate way. They have also engaged in a continuing battle with limited partnerships because limited partnerships are used as tax shelters and that's a dirty word around the I.R.S., but nevertheless, in balance, it's my feeling that a limited partnership involves you with less legal complications.

In view of the fact that a large part of the potential return on investment from a hydroelectric project is derived from full use of its tax benefits, we go on in the next subsection of the manual to discuss not only what we call the general Federal Income Tax considerations confronting small scale hydro but also some of the details. Roughly the kind of tax benefits we're talking about for a small scale hydro site include, obviously, the interest deductions on whatever debt is involved, the depreciation which you may be able to achieve on an accelerated basis on the equipment that qualifies as that for the project, and the important investment tax credit and energy tax credit.

I would like to mention here just some of the important issues involved in determining the availability of these tax benefits. With respect to the accelerated depreciation, you need to decide what kind of property your project actually entails and divide it essentially between what the Code calls "Section 1250 property" and "Section 1245 property." "Section 1245 property" is limited in its accelerated depreciation to what they call 150% declining balance; "Section 1250 property" is fully available for double declining balance depreciation. Depreciation taken to excess of straight line is subject to recapture upon disposal of that property for "Section 1250 property." For "Section 1245 property" all depreciation taken is subject to recapture upon sale. Most of the property that you would be talking about in small scale hydro projects would be "1245 property."

An important tax benefit that I didn't mention previously is, of course, the opportunity or potential opportunity for capital gains upon sale or exchange of the property at the end of the investor's holding period. And that can be substantial or not, depending on a number of factors. Probably the most important of which is your power sales arrangement, and I'll get into that a little bit later.

With respect to the availability of investment tax credit and the energy tax credit, putting aside the basic criterion for a moment, some areas where you may have some vulnerability or that may become important as you try to assess just how much you can get in terms of tax benefits include consideration of whether or not you're going to be moving your impoundment structure if you have to completely rebuild your dam. A literal reading of the Crude Oil Windfall Profits Tax Act sections would suggest that you may not have the availability of the energy tax credit if you relocate the dam. Now, many of us who worked on the hydro provisions of the Crude Oil Windfall Profits Tax Act think that's very bad policy, but we also note that the I.R.S. has been extremely tough on any kind of tax subsidy program and, where possible, has taken the position that will result in the least loss of tax revenue. I can expect some resistance on this issue from them, and suggest that you consider the possible desirability of obtaining an advance commitment from the service which you can do through a variety of procedures, including private letter ruling. I'm sure you'll agree that the loss of an 11% energy tax credit when you're assuming its need for the viability of the project could be a substantial problem for you.

Another area where you may experience some problems in obtaining the energy tax credit includes the extent to which it will be available for cases where you're going to enlarge the impoundment structure. There is a requirement in the conditions for the energy tax credit for hydro facilities that you do not enlarge the dam. We think the best public policy reading of that section, and probably what the committee intended, was that in cases where you are going to enlarge a dam because it makes good sense to do so, and where you can do so so as not to cause severe environmental problems, you then should at least be eligible for the full credit on all the costs related to development which do not extend to the enlargement of the facility. However, it is possible that the service, again, would take a very literal stance in this area and say, "No, if you enlarge the facility you don't get any energy tax credit." Again, I think you can see how damaging that kind of result would be if you hadn't planned for it. And again, I think it suggests a possible need to try to settle that in advance with the service if it is a factor at your site.

A final area under the energy tax credit is the consideration of whether or not you're using used property or new property, and this, I guess, is of primary concern in selection of your turbines and generators. Used property is not subject to the energy tax credit. And essentially, used property under standard code approaches has been property whose original use is initiated by the taxpayer in connection with the project in question. In addition to the possible loss of the energy tax credit for used property, you are subject to a cap, a ceiling amount, on the availability of the original investment tax credit of 10%. So, you suffer the possibility of two losses here in certain cases.

And finally with respect to the credits, you will not be able to obtain the energy tax credit in cases where you are using what they call subsidized financing. Essentially that includes low-interest loans and it includes Industrial Development Authority situations where you're financing your project with tax-exempt debt. So to the extent that you make use of those things, the service will disallow that portion of the property for purposes of the Investment Tax Credit. It's a tradeoff that you must consider.

This brings us into a discussion of what we call the tax considerations involved in our flow-through devices. Here we're talking primarily about limited partnerships. We chose to deal with these because of our determination that the limited partnership form was probably the most appropriate tax flow-through device for this kind of a project. Much of the analysis that we go through for that form, however, is equally applicable to Subchapter S corporation, if that's the way you choose to go. The most important things you have to bear in mind when you're trying to ensure full flow-through tax benefits for these projects through a limited partnership are what is called the at-risk limitation of deductions and possibly the allocation of deductions and losses. The allocation question deals with how you structure your partnership form and the rough guidlines in terms of allocating the tax benefits within the partnership. This is largely based on the formula whereby the various investors in the project derive their profits and losses. So if a limited partnership is structured so that all the investors are getting is the losses and they share a drastically reduced amount in the profits, then you may have something the code considers suspect. There are lots of complexities there that need to be addressed; you're going to need some tax advice from a very competent professional.

The same, I guess, would hold for the limitations on loss deductions which include interest and depreciation deductions to the taxpayer's amount at risk. This rule came out of the Tax Reform Act of 1976 and essentially it says that an investor's ability to take loss deductions from an activity is limited to his amount at-risk in that activity. This is of primary importance to the limited partner in a limited partnership because it may well be if these projects are financed the way other limited partnerships have been structured that the limited partner does not have any liability for the project loan. He is nonrecourse, as they say, or the loan is nonrecourse to him. In those circumstances, the service will essentially limit his ability to take deductions from the activity to his amount of capital contribution or to the income that comes from the project itself. And essentially what this means for your average hydro project is that many of the advantages of accelerated depreciation will be unavailable to an investor who is not willing to fully commit himself at recourse liability on the loan. The only thing that is not subject to the at-risk limitation on deductions right now is what they call investments in real estate

or holding real estate activities. There have been some suggestions by some investment advisors that some part of the hydro project may qualify for that kind of treatment. I would say that would be something that would be difficult to prove to the service. I certainly won't say it's impossible, but I'd say you can expect a challenge if they discover it on your return.

We include in the manual a discussion of the impact of proposed tax legislation on small scale hydro development, and there are a couple of items here that are interesting to note. The proposed 10-5-3 depreciation approach would be beneficial to small scale hydro projects since under current rules the minimum asset/depreciation range is 40 years. It's actually...the official figure 50 years and you get a 20% ± variation. Of course, for any hydro project, to the extent that you can go to the service and justify a shorter depreciation life based on the actual physical property, the vulnerability of the property to physical deterioration, you can obtain a shorter life -- physical or economic deterioration that is. We think that many of you can make a showing that even at this time your facility should qualify for a shorter depreciation life. In other words, it looks like things like turbines don't really last 50 years any more, or certainly they don't in certain applications. A lot of this is very site specific. It depends on a number of things, including the content of the water in the area where you're locating your turbines. Be that as it may, the proposed 10-5-3 improvement would give you increased opportunities for depreciation and certainly the ability to obtain an attractive return on your project much quicker than you could under the current rules.

You should bear in mind that the opportunities for these increased depreciation deductions are going to be limited to your amount at risk so that if you're structuring a limited partnership you're going to have to come up with some way of flowing through those depreciation allowances and essentially that's going to mean convincing your equity investors that they should assume a larger part of the liability for the project in some way.

The next item of the proposed legislation would be rather negative to small scale hydro development, and that is the proposed revision in the Investment Tax Credit which would expose Investment Tax Credits and Energy Tax Credits for the first time to this at-risk rule treatment. As a matter of fact, the proposed legislation as it currently reads would substantially curtail the availability of the credits for these facilities and this provision is contained in House Bill 2400, Senate Bill 683. It is Section 203G of both of those. Essentially, as it reads now, the investors or taxpayers ability to take the credits would be restricted to the normal credit percentage of what they call his qualified basis in the property that could not exceed his amount at risk. The amount at risk is defined in the same way as it is for limitations on losses which is a current division of the code. So, to the extent that an investor was not liable on the debit for the project, and to the extent that that investor has not contributed capital for the facility, then he would be constrained from taking an energy tax credit that would be equal to the full amount of the appropriate percentage of his qualifying property. I think an example makes the point better than a pure description.

Under current law, for instance, if you had $10,000 of what they call qualifying investment property, you would have the opportunity for taking the full 21% combination of credits, which would leave you with $2100 in credit. That would be available to you regardless of what your amount at risk in the project actually was. If the rule goes through as currently written, if for example, you had only

invested $5000 and you had not agreed to be liable for any of the project debt, then you would only be able to take the 21% of that $5000. I think you can see how much that affects your return from the project. There are a number of people that have learned of this that are trying to persuade the Senate Finance Committee to reconsider that approach, and we think that's appropriate. As a matter of fact, we have discussed the issue of the impact of the change with a couple of senators on that committee. And I suggest to you that if any of you are considering a limited partnership approach to the development of your projects that you might want to have some conversations with your own senators and representatives. The House has concluded public hearings on the issue, but it still can be changed in the committee. The Senate Bill has recently concluded public hearings, but the record is still open; and if you are interested and if you find this to be detrimental to your development approach, you might want to get some evidence into the record. You can find out how to do that by contacting your own senators and congressmen.

The next section of the manual deals with what we call sources of funds. And essentially what we've tried to do here is to sketch some of the opportunities and some of the key actors in the financial planning for your project. We talk about commercial banks, syndicators, manufacturers, investment bankers, state and municipal industrial development authorities. They all offer different kinds of opportunities. They all fill needs for different financial concerns for different stages of the project, although there's obviously some overlap. The summary, or general caveat, is to locate a source of advice or, perhaps, a source of full-range financial assistance from those persons who can enable you to yield the biggest return from the project. Now that sounds like simplistic advice, but I think if you go through the analysis necessary to make that determination, you will find that it is a very valuable piece of advice. You can get these people to give you estimates of their services and how they can help you develop your project relatively easily.

This last section, which is probably the section we consider most important in the private manual, deals with what we call general considerations and strategy. Essentially, we get into questions how you decide in a very generic kind of way how to make the multiple choices involved in proceeding with the financing of your project. As I suggested earlier, the overlying theme here is risk versus return. For instance, if you can find some investors who are willing...or you personally can provide the necessary security for the project through outside means -- and I'm talking primarily about your own net worth or your investor's net worth -- then it may well be that you don't want to have your return on the project constrained by a long-term purchase-power contract with some kind of ceiling on the return that you receive. Conversely, if you are unable to offer that kind of security personally, or you decide that it is not a good risk for your own investment needs, then you will probably need a long-term purchase-power contract. Some options of debt financing which I think may well be mentioned tomorrow, include fixed-rate debt which is kind of difficult to come up with. However, you are seeing some flexibility, I think, from the class of lenders who typically have provided fixed-debt -- casualty insurance companies, for instance. There is some indication that in return for a share of the equity in the project they will be willing to give you a fixed-rate debt a competitive market rates. However, if they do that and if they are looking for benefits primarily related to the capital appreciation of that asset, then they are not going to want to be constrained on the upside by a long-term power contract with some kind of ceiling.

There is an entire range of possible revenue stream forms and multiple kinds of power-sales contract, that can come out of the negotiations between the developer and the utility. As you evaluate each kind of approach -- we suggest some of the ones that are most familiar to us -- you want to take a careful look about what kind of return would be available to you if you went with that stream and what are the assumptions on which that return is based? For instance, you are risk averse and you don't believe that energy prices are going to continue to rise, or you can discover that your utility is on the verge of instituting a very successful nuclear construction program which will, in a sense, keep avoided costs down over an intermediate period of time: That may indicate to you that your upside is limited by external factors, so perhaps you should be more willing to go with a long-term power contract with a levelized payment schedule. It may be that your project is one that cannot show economic viability during its initial stages at current avoided cost for your area. If that's true, then you may well want to go with a levelized power contract. And as I said, there are multiple factors that need to be considered here. In addition, you want to make sure that your determinations are done on an after-tax basis. And there again, you want to make sure that your assumptions about what is available on an after-tax basis are the best possible. I would counsel the use of experienced tax professionals in this area to make sure that you get the expected result.

I guess many of the same considerations that I mentioned earlier in the private manual are equally appropriate for a public developer except your focus and some assumptions are going to be slightly altered. In particular, we talk about what kinds of things should be accomplished in the reconnaissance study, the feasibility study, and we discuss factors bearing on obtaining the necessary permits, licenses, etc., with some overview of very key issues in that regard, such as the municipal preference and the question of a hybrid development which I've already alluded to this morning.

As a public entity goes through this first stage of evaluating how to deal with a site that they may own or may be able to obtain, we think one of the key questions is whether or not they actually have the authority to develop. Now, as part of the licensing process, certainly at the Federal level they find themselves in a competing application situation. Thus, we think that it's appropriate for these public entities to determine early on in the process of deciding what to do with their site whether or not they do have all necessary statutory authority or -- and it's going to be primarily statutory -- to engage in the kind of financial arrangements that are essential to doing that and to engage in wholesale power sales, the sales of electricity to persons other than end users. If there's one thing that we've discovered in the course of our technical assistance work with the various states, it's that many public entities do not currently have that kind of authority. The may well have the authority to create municipal distribution systems, but that authority is not automatically synonymous with the authority to develop the site for the exclusive purpose of wholesale sales to some other entity or utility. And that's going to be largely a question of state constitutional law or state statute.

Ok, we spend some time in the public manual discussing power contract negotiations. The discussion of tha issue in this manual is much more abbreviated than it is in the private manual, and this is one of the other areas in which if you are a public developer you would want to have access to the private manual for a more complete discussion. The private developer is going to have very little need to review the information in the public manual. We feel that it is completely self-contained and any information that he needs in this area, beyond what he can get from professional counsel, he will find there. However, a public developer may well have some desire to look at the private manual because of the fact that many of the items discussed in the private manual are equally applicable to him.

And in particular, items like power sales negotiations are discussed more thoroughly and in more detail in the private manual.

The next chapter of the public manual, which we call General Organizational and Business Consideration, discusses the authorization to proceed with Small Scale Hydro (SSH) development. We talk about possible alternative ways that the municipality can proceed to bring their project on line, and I just alluded to these this morning, but to recount they include having the public entity: (1) develop the project itself, and proceed through all phases of the project; (2) sell the site outright; (3) lease the site on a long-term or short-term basis; (4) proceed with some kind of a joint development. I think I've already mentioned some considerations that need to be undertaken in trying to evaluate between the various opportunities there. However, on page 15 of the manual, we go through what we consider is one of the general methodologies for deciding between the various opportunities for development. Essentially this is nothing particularly new here, but it does seem to be something that is relatively new to many of the decision makers in the small municipalities that haven't had to deal with what you do with a potential revenue-producing asset like this. What we suggest you do (just to get an idea of what the competing economic returns available to that public entity are under the various forms of development) is complete a present-value analysis of the anticipated revenues from each one of these four routes. Now then, you're going to have to make some assumptions in doing that that may prove somewhat inaccurate upon later examination. As we've said for the private manual, you just have to use the best information you have available. We think it's prudent, as it is in most investment decisions, to try to be somewhat conservative in those assumptions.

In our example in the manual we made sure to include things like the possible impact on the municipality's tax revenues under the various forms of proceeding, and the impact of various types of municipal revenue flow structures or various types of revenue streams that might result from the different kinds of development opportunities. Of course one of the most important factors in any kind of present-value analysis is when you're actually going to be getting the benefits and, obviously, the more quickly you derive these economic benefits, the more value they are to you in a present-value sense. Of course, when you undertake this kind of analysis, you are sensitive to some difficult questions about what, for instance, is the appropriate discount rate for the municipality. For the purposes of our calculations -- and we don't mean to suggest this is the only way you can do it -- we just used the expected municipal borrowing rate and assumed that would be the municipal developer's opportunity cost.

The next phase of the public manual discusses various sources of funding and specifically how a municipal entity will be able to obtain the necessary funds for development. As was true for the private entity, the source of funds, the kind of financial assistance or advice that you can get, depends on which stage of the project you're talking about. The projects have different needs in their early stages and different sources of funding for feasibility analysis, upfront reconnaissance, advance design work, than they do, for instance, for the construction period and certainly both these periods have characteristics which differ from those surrounding the ultimate long-term takeout which actually makes the construction loan work. In that regard a public entity may have particular difficulty obtaining the necessary upfront funds. That is, if the public entity happens to be located in a state that does not provide for planning bonds, or does not enable you to issue your bonds early in anticipation of an ultimate bond issue, that entity may have insufficient capital to even complete a

feasibility analysis. Some public entities may have the necessary authority to issue planning bonds or will have some flexibility in their bonding statutes, or may have a sufficient draw on extra funds to finance the upfront cost of that rough screening process. Other options include staggering the feasibility study in various stages so that you get a very quick thumbnail assessment of the viability of the project (which you'd probably do anyway) and, perhaps, getting enough information there in order to satisfy the requirements of potential lenders in the bond marketplace and also the bond counselor who'd have to sign off on the issue. Finally, it may be possible to locate an engineering-consulting firm that will, in a sense, advance the municipality the credit to accomplish the early studies in anticipation of later development work.

We go into some detail about the Federal laws that overlay the bonding for public facilities. There is an opportunity to finance these projects through tax-exempt debt, both as a public developer and through a private developer, under certain circumstances. The ability to do that is constrained by the Internal Revenue Code requirements, basically section 103(b), pertaining to when the interest on bonds of a municipal entity or a public entity will be regarded exempt from Federal Income Taxation. This tax-exempt status gives you a marketplace interest rate differential between taxable and tax-exempt debt. Private developers can also obtain tax-exempt interest rates if they can fit into one of a number of exceptions. The general rule is that if these funds are going to ultimately be used by a non-exempt entity -- and of course a private developer is generally a non-exempt entity -- then the interest on those bonds will be taxable unless you meet one of the further exceptions under the Internal Revenue Code, section 103(b). Those exceptions include the local furnishing of electricity exception and small issue exemptions. Of course there is the new Crude Oil Windfall Profits Tax exemption which practically extends only to public projects. So private developers would be able to gain access to tax-exempt financing through a state entity that was established to provide that kind of financing; in most states that would be an industrial development authority or its equivalent. Since they would be selling in most cases to a non-exempt entity (an investor owned utility), public entities would be able to obtain tax-exempt financing if they could meet one of those exceptions, or if they could meet the new Crude Oil Windfall Profits Tax Act exemption which is limited to sites of up to 125 megawatts in size. It's fully available to sites only up to 25 megawatts in size; the exemption is available on a reduced, gradually declining basis between 25 and 125 megawatts.

I did want to note a couple of potential problem areas, in trying to use that exemption if you're a public entity. One of those is that the new exemption carries with it a requirement for registration. The bonds issued under that exemption have to be in what they call registered form as opposed to bearer form, which has been the general rule for tax-exempt bonds. It's not the only bond that's subject to that requirement, but it appears to be the Internal Revenue Service's desired trend because it makes it easier for them to keep up with where those bonds are located. Since it is one of the first to be saddled with that requirement, it means that there is going to be at least some short-term impact on the marketability and probably the interest rate for those bonds.

For example, a recent public hydro project in California originally attracted a number of underwriters to bid on the bonds that were going to be sold by that entity. At the last day before the bids were required to be provided, all but one of those potential underwriters withdrew their participation or decided not

to go through a bid. The reason they cited was the registration requirement. In addition, the one entity that did remain and did continue to participate did so only by offering to take the bonds on a substantially discounted basis; I think something like 90% of par. The interest rate was about the conventional market rate for a debt of that kind. That was very disappointing to the municipal entity that was undertaking the project and nearly required them to go through a new approval process to authorize sufficient funds (at the discount from par) to build the project.

I guess we have a few moments to take any questions.

Q. What has been your experience with the Farmers Home Administration as a financing agent?

A. Well, I guess it's fair to say that a few projects were undertaken under their programs, particularly back when the President's Rural Energy Initiative was operative. However, I haven't seen any recent interest on the part of Farmers Home in continuing with that program. I guess in a special situation, you may well be able to fit the criteria that will enable you to get a project financed that way.

Q. Bill, Do you have any experience with recognition of the FERC dam safety program by financial institutions as a justification for a lower interest rate in the financing of such projects? That is, do lending institutions make any allowance for a successful report under this program?

A. I haven't encountered anything like that. I'd have to say that I don't think that most instituions would reduce the interest rate on loans to projects at such structures. However, a satisfactory assessment under such a program might make some lenders more willing to provide a loan for the project.

HYDROPOWER: RENEWABLE ENERGY SOURCE

Susan M. Shanaman
Chairman, Pennsylvania Public Utility Commission

Chairman Shanaman is a 1968 graduate of Lebanon Valley College (B.A. - Psychology) and a 1971 graduate of the Dickinson School of Law (J.D.). She was appointed a member of the Public Utility Commission by Governor Thornburgh on November 16, 1979 and named Chairman on January 7, 1980.

Prior to joining the Commission, Chairman Shanaman was Committee Counsel and Staff Counsel to the Minority, State Senate of Pennsylvania. In these capacities she worked extensively with individual businesses, steel, coal and foundry industries, the public utility industry, consumer groups and local government associates in developing, drafting and amending legislature proposals. Chairman Shanaman, together with Commissioner Cawley, was co-draftsman of Acts 215 and 216 - the first major revision of public utility laws in Pennsylvania since 1937.

Chairman Shanaman currently serves on a wide variety of Boards and Commissions including the Governor's Energy Council, Environmental Quality Board, the Communications Subcommittee of the National Association of Regulatory Utility Commissioners (NARUC) and the Governor's Tax Commission. In addition, she is an Executive Member of the Great Lakes Conference on Public Utility Commissioners and a member of the NARUC Advisory Council to the Nuclear Electric Insurance Limited Board.

The PUC and the Department of Energy share a mutual interest -- energy efficiency and conservation of scarce natural resources. Conservation is perhaps the most important term applicable to ensuring a healthy energy future.

Energy conservation begins with education. This Commission has encouraged the utility industry in Pennsylvania to fulfill the unwritten responsibility of informing consumers that the uneven distribution and consumption of resources is morally, ethically and practically unacceptable. I am pleased to note that several electric utility companies in the Commonwealth have already taken the initiative to establish working energy education advisory councils to develop energy-related curriculum programs for local schools.

The ultimate purpose of the Commission's and the utilities' development of various conservation activities is to reduce the long run net energy cost to ratepayers and to provide for additional future supplies. The long run net cost includes the ratepayers' costs of purchasing energy from the utility, as well as the full cost of energy consumption, such as the initial purchase and maintenance costs of energy-consuming equipment.

If utility customers are going to reduce their general level of consumption, they will have to make changes in both energy consumption behavior and energy-consuming equipment. Customer conservation can be accomplished by reducing the use of the energy equipment. These behavior changes range from lifestyle changes by residential customers, such as reducing unnecessary appliance use, to major production changes by large industrial customers.

In order to induce customers to make the desired consumption behavior and investment changes, utility managers have and must continue to develop cost-effective utility services and economic incentives. Because these conservation opportunities will reduce ratepayers' future energy requirements, utility managers must view these opportunities as future energy supply options.

The PUC has always been interested in the supply of energy and its cost, and has for many years permitted the costs of certain types of research and development to be included in the operation costs of rate increases. Our Bureau of Conservation, Economics and Energy Planning, established by the State Legislature in 1976, researches all matters within the Commission's jurisdiction. It also advises us of the results thereof in order to enable the Commission to provide prospective regulation in the best interest of all parties concerned.

Hydropower is unique in terms of its history and its characteristics. We in the Commission feel that small-scale hydroelectric power is moving from the realm of research to actual implementation.

Hydropower is an old and proven technology which has been reborn, due to rising fuel prices. Early technology is being upgraded and the impact of requirements, such as environmental limitations and multiple uses, are being resolved.

The growth in energy use in America parallels the growth in the strength of our country. Its earliest growth was through small-scale hydro. Two uses, mechanical power at grist mills and transportation via canals, accounted for nearly all of the hydro energy that was developed until near the end of the 19th century. The value of that energy was considered to be the value of manpower, horsepower, or steam engine energy that would have been needed to do the job.

With the introduction of electric generators, another way to use hydro energy became available. Initially, of course, small-scale hydro serving a very limited area was the manner in which this energy source was utilized. In accord with man's innate desire to build bigger and better, larger dams and hydroelectric facilities were constructed. Until the idea of multi-purpose dams was fully coordinated, the value of hydroelectric energy was compared to the value of generating it by other means.

Along with the higher costs of generating electricity 40 to 50 years ago, hydroelectric energy was considered to be an attractive alternate source of energy. However, as the "bigger is better" syndrome was applied to fossil-fuel-fired turbine generating plants, the costs to maintain the small-scale hydro units became prohibitive. As a result, utilities ended up retiring such plants.

The advent of the oil embargo, the recent shortage of natural gas, the impact of nuclear energy (especially since the Three Mile Island incident), the many environmental requirements and the inexpensive application of automatic controls on small-scale hydroelectric equipment has resulted in the need for a new prudent review of the potential for the application of small-scale hydroelectric power throughout the country.

Of all its advantages, the most important and most unique characteristic about hydropower is that its source of fuel is renewable. The energy obtained permits the conservation of depletable energy sources such as coal, oil and natural gas.

There is, however, one major catch; the equipment used to process this fuel is expensive. Capital costs for hydroplants can be twice that of conventional fossil-fired plants. In addition, the output from hydroplants cannot be controlled as easily. Lack of water, too much water and minimum flow requirements can each have a significant impact on the amount of power that can be obtained from a particular hydroplant. Nevertheless, hydropower can provide a valuable supplement to a utility company's facilities.

A great deal has been accomplished at both the State and Federal level to encourage hydropower development. Passage of the National Energy Act, which includes the Public Utility Regulatory Policies Act of 1978 and the creation of tax incentives, has been particularly helpful.

The Federal Energy Regulatory Commission has also made considerable progress in reducing both the complexity of and the time required for processing applications for permits and licenses. It has also removed many of the stumbling blocks which faced hydropower developers, due to regulations pertaining to the implementation of Section 210 of PURPA.

The Public Utility Commission entered the picture with the implementation of Section 210. Prior to the enactment of Act 216 in Pennsylvania and the NEA in Washington, this Commission would have had little legal authority to become involved with small-scale hydroelectric projects. The PUC has regulatory powers over generation installed with the intent that the electricity generated be sold to customers other than the generation equipment owners and in other than bulk quantities. We became involved only if the small-scale hydroelectric site was developed by one of the major investor-owned utilities and integrated into its system, or if it was developed by an entrepreneur for sales in small quantities to nonowners of the site.

Now, with Section 210 our role has been expanded considerably. On April 10th, the Commission adopted a set of draft regulations which will be published for comment very shortly. I would urge each of you to review those regulations and share your thoughts on them with us. We feel that our draft regulations will help to promote the development of hydropower. They will be discussed in much greater detail tomorrow by Richard Sandusky, Chief of Research Development and New Energy Technology in our Bureau of CEEP.

Pennsylvania can and should be a pioneer in the development and use of small-scale hydroelectric projects. The State is well endowed with water and also has a small-scale hydroelectric industry. There are currently more than 2,300 dams in Pennsylvania, and according to DOE, the Commonwealth has the potential to double our generation of electricity through hydroelectric projects using existing dams. This means Pennsylvania could be generating the same amount of electricity that would be produced by four nuclear power plants the size of Three Mile Island.

According to the recent energy report sponsored by the Ford Foundation, the estimated maximum worldwide potential for hydropower is the equivalent of three million megawatts of installed electrical capacity -- equivalent to 3,000 large nuclear plants. In the United States, the present hydroelectric capacity of nearly 70,000 megawatts represents about 40% of the estimated potential. In Pennsylvania, the total potential is about 14,800 megawatts.

Hydropower, because it is available directly as mechanical rather than as thermal energy, is naturally suited for producing electricity or doing mechanical work directly. It is also one of the more easily storable forms of solar energy, which can be used as needed. This accounts for the fact that, both for the United States and the world as a whole, the average load factors for hydroelectric plants are a relatively high 50%. Therefore, hydropower is a highly desirable source of alternative energy. It has great promise, especially where small-scale hydropower may be usable without expensive power transportation and distribution grids.

Once thought to be uneconomical, the generation of electricity at small-scale hydroelectric installations is now looked upon by the Federal Government as a way of reducing U.S. dependence on costly and undependable supplies of foreign oil. Two dams in Pennsylvania were among 51 sites in the country to be chosen to receive Federal money last fall for the development of hydropower. The projects include dams operated by the Army Corps of Engineers at Emsworth on the Ohio River and on the Raystown branch of the Juniata River in Huntingdon County. Both projects were awarded low-interest loans for studies on the feasibility of using the fall of water to generate power. In both cases, the loans were awarded to the Allegheny Electric Cooperative, which supplies power to 13 rural electric systems in Pennsylvania and one in New Jersey.

In a report issued by the Army Corps of Engineers in late 1979, it was estimated that the hydroelectric generating capacity could be doubled if the thousands of abandoned and partially used dams were fully utilized. The Corps said full utilization of these dams could increase the maximum generating capacities of water power from 63 million kilowatts to nearly 160 million. Building new dams on the other sites could run the capacity up by another 354 million kilowatts.

Doubling the hydroelectric output by using existing dams could make a sizable dent in oil imports and probably save money besides. In any event, the money spent on fitting and refitting American dams with generators would not be going to OPEC price gougers.

This Commission believes that Pennsylvania has a great deal to gain by promoting the development of its hydro sites. According to a recent article in PARADE magazine, electric rates are highest in the Northeast and lowest in the Northwest, where hydropower is more abundant. If we commit ourselves to the success of small-scale hydroplants, we will help reduce the cost of electric generation.

I believe the importance of hydroelectric generation will be discerned when we as regulators, as well as the general public, recognize that each kilowatt hour of installed usable hydroelectric capacity represents a kilowatt of avoided investment in nuclear, coal, gas or oil generation. Each of these alternatives is subject to variables far removed from the control of utilities or regulators.

Although we can never expect hydropower to totally replace any of the alternatives just mentioned, its use as a source of energy which can be utilized to lessen the effects of an abrupt disruption in the supply of any one of the alternatives has been greatly underestimated. Through innovative regulatory incentives both at the State and Federal levels, we must continue to encourage the full development of our hydroelectric resources. The end result will be more stable electric rates much less subject to external factors over which we have no control.

In closing, let me state an optimistic thought about the human race: We never stop investigating. We are never satisfied that we know enough to get by. Every question we answer leads to another question. This has perhaps become the greatest survival trick of our species. It certainly can and should carry through to those of you here today so that the future will be something to look forward to for generations to come.

CAPITAL AND HYDROELECTRIC POWER

Temple Bayliss
Director of Energy Division
Virginia State Office of Emergency & Energy Services

A native of Goochland County, Temple graduated with honors in physics from Bowdoin College in Maine in 1961 and received his Ph.D. in physics from the University of Virginia in 1967. Prior to joining the Virginia Energy Office as Conservation Coordinator in 1975, he taught at Virginia Commonwealth University.

As a member of the Energy Office Staff, he served as a consultant to the Electricity Cost Commission on load management and on the potential effect of conservation on the demand for electric power. He assisted in the preparation of Energy and Virginia's Future, the report of the Virginia Energy Resource Advisory Commission, and the Virginia Energy Management and Conservation Plan, the State's response to the Energy Policy and Conservation Act.

In March of 1978, the Energy Office was merged into the State Office of Emergency and Energy Services. Temple now serves as Director of the Energy Division of the combined agency.

It has been about seven months since I saw many of these same charming faces at Lieutenant Governor Robb's excellent hydropower conference. There has been a lot of wind through the trees since then and that wind may well blow away your loan program and my agency.

I had the opportunity a couple of weeks ago to look over the draft working papers put together in preparation for the National Energy Plan III, and I want to paraphrase those for you. What they said was: There may be an energy problem in the United States, but, if so, it is primarily an economic problem and it is going to be up to the private sector to solve it. Amen. Over and out.

Now there may be painful elements to that point of view and some things that will not work out terribly well, but I think on the whole it represents a very sound and sensible policy. I believe the energy problem is largely an economic difficulty. In particular, I believe it is a problem of capital availability. After all, if we had enough capital, we could put solar collectors on everybody's roof, we could insulate all the walls of all the houses whose walls need insulation, we could build any synfuels plants that we needed or we could buy every household in the country a little two-passenger car with a diesel engine which would get 50 or 60 miles per gallon. Such cars could be used whenever we did not need a big cargo-carrying capacity or did not need to go on a very long trip with the whole family.

If we could do all these things, which are certainly technologically possible, then we would have enough oil for generations to come and the energy problem would disappear for a very long time. That we cannot do is simply an indication that we do not have enough capital.

How serious is the shortage of capital at the present time? Well, one ready measure of the shortage of capital is the interest rate which, as everybody knows, is now around 20%. A few months ago I was talking to an economist and I let loose the point of view that the interest rate represented an ephemeral and largely artificial factor which was needlessly getting in the way of certain energy-related projects dear to my heart. The economist absolutely wiped up the floor with my ideas. He reminded me that the very high interest rate of the moment indicates the enormous capital requirements for things like drilling for additional oil supplies, building new housing which, of course, would be more fuel-efficient than existing housing, buying new cars which would, in general, be much more fuel-efficient than older cars and doing countless other things, many of which are related to the energy problem. So, although there is nothing permanent about the present level of interest rates, yet that level does indicate the intensity of the nation's need for capital and that need for capital is a result in many ways of the energy problem itself.

Now when it comes to dealing with a lack of capital, the government does seem to me to be uniquely ill-equipped to lead the charge. The government has no rational mechanism whatsoever for allocating capital between competing alternatives. The alternatives with which we can deal with the energy problem are almost innumerable. We can use capital for hydroelectric power, capital for conservation, capital to build windmills, capital for solar energy. How do we make the choices between such alternatives? Well, the only way the government has of moving capital around is a series of ad hoc subsidies; a tax credit for this, a guaranteed loan for that. I would suggest to you that even though the results of the subsidies have, in many cases, been extremely beneficial and they have gotten some very fine projects going, yet in the long run this approach is going to give us a serious misallocation of capital and, since a lack of capital is at the heart of the matter, it will ultimately make matters worse. A capital market free to respond to economic forces will not give a perfect allocation of capital, but it is at least a system with some capability for weighing alternatives.

For those of us interested in hydroelectric power then, I think we are going to have to turn our attention away from government as a source of capital and look instead towards financing from the private sector. We will have to focus our attention on how to get an adequate stream of revenue from hydroelectric projects in order to obtain private capital in what will remain a very tight and very competitive market. To do that, I think we have to join together in a really strong Virginia hydropower association and fight our battles with the utilities and the State Corporation Commission.

Now I would suggest something in that line that is bothering me. Out here in the Western part of the state, we are looking at costs for electricity, on the residential rate schedule in winter for a typical electric-heating customer, of about 3.75¢ per KW hour. That is a lower cost for this premium highly-flexible form of energy -- per BTU delivered -- than for number 2 oil at any achievable efficiency. Wherever you get the cost of oil significantly above the cost for electricity, you have got a very remarkable situation which, I think, is probably going to have to change; and, as it changes, we are likely to find a large increase in the demand for electric power.

When utilities are able to scale back their expansion plans, which is now the case in this state, then extra generating capacity is not so valuable. I have the feeling, however, partly because of the relationship of oil prices to electricity prices, that the era of reducing planned growth in generating plant is ending in Virginia, and we are coming to a time where new generating facilities must again be hurried toward completion instead of slowed down. I believe we ought to work for financial arrangements which will reflect the likelihood of such a shift.

Only by ensuring that the value of the capacity of a hydroelectric plant is fully reflected in what it gets for its sold power will hydroelectricity be able to compete fairly for scarce private capital, and only when it can compete fairly will hydro projects be built in Virginia. The time in which renewable energy projects could turn to the government for relief from the rigors of the marketplace for capital is over.

CURRENT ISSUES AT FERC

DONALD A. GIAMPAOLI

F.E.R.C.

MAY 28, 1981

MR. GIAMPAOLI IS A GRADUATE OF THE UNIVERSITY OF SANTA CLARA IN CALIFORNIA (BS-CE) AND HOLDS A MASTERS DEGREE IN CIVIL ENGINEERING FROM CATHOLIC UNIVERSITY OF AMERICA IN WASHINGTON, D.C. HE IS A CERTIFIED PROFESSIONAL CONSTRUCTION MANAGER AND REGISTERED PROFESSIONAL ENGINEER IN WASHINGTON, D.C.

PRESENTLY HE IS DEPUTY DIRECTOR, DIVISION OF HYDROPOWER LICENSING, FEDERAL ENERGY REGULATORY COMMISSION. HIS INTERESTS IN HISTORIC RESTORATION AND CIVIL ENGINEERING ACTIVITIES SERVE HIM WELL IN THIS CAPACITY.

PRIOR GOVERNMENT SERVICE WAS WITH THE DEPARTMENT OF INTERIOR WITH THE UNITED STATES BUREAU OF RECLAMATION.

I'm going to deviate a bit from the normal type of presentation that I usually give, which is somewhat on the technical side, and discuss our licensing program. Also, I'm going to provide to you some statistical information concerning hydropower and the activities at the Federal Regulatory Commission. I'll talk about the jurisdiction of the Federal Power Act, changes in FERC regulations to date, the problem areas that we've been encountering, and some possible solutions to those problems; particularly regarding preliminary permits, the issue of competition, and licenses. Some discussion about legislation and, lastly, future actions by the commission and then, hopefully, we'll have an opportunity for a question-and-answer session.

We have at the Commission, presently under license, over 38 million kilowatts (conventional and reversible), and since 1975 FERC has licensed 9.5 million kilowatts. Federal capacity approximates 36 million kilowatts (conventional and reversible). As of January 1 of this year, there's a total of about 64 million kilowatts of installed conventional capacity in the United States. By the year 2000, under a median projection mix, the total hydropower capacity could be 83,000 to 166,000 megawatts as forecast by the National Hydropower Study -- those of you who attended the last study workshop in Washington, D.C., two days ago, most likely heard this figure. This indicates new hydropower capacity from 7,000 to 90,000 megawatts (including pumped storage).

I'm going to switch to activities at government dams. We have considerable interest in development at government dams by preliminary permit and license applications at dams primarily those of the Corps of Engineers and the Bureau of Reclamation. This agency, for those of you not familiar with the West, serves the 17 western states or those states west of the 100th meridian -- the agency that built Hoover Dam and Grand Coulee. As of March 31, we have a total of 368 preliminary permit applications at dams owned by the Corps of Engineers. I'm including both pending and issued preliminary permits. And, as far as the Bureau of Reclamation is concerned, we have 175 preliminary permit applications.

Now to discuss some of the statistics that Anita was talking about earlier. The preliminary permits to be received in 1981, our estimate is that we will receive 1,800. To give you a perspective: the actual receipts in fiscal year 1980 were 501; in 1979, 76; in 1978, 36; in 1977, 18; and in 1976, 12. We expect to issue approximately 1,200 preliminary permits in fiscal year 1981, which means we'll have a backlog. In 1980 we issued 191. To date, we've issued over 400 preliminary permits; and of those, 50% are 5 megawatts or less. We estimate issuing 250 licenses and exemptions in 1981. We have issued 165 licenses and exemptions to date. At present, we have approximately 18 million kilowatts of capacity in some form or stage of planning and design; 18 million kilowatts!

Some of the discussions that we've had so far, and I assume some of the discussions that will occur tomorrow, will point to certain parts of the Federal Power Act, 7(a) municipal preference, and problems associated with that. Our jurisdiction comes under Part I of the Federal Power Act, the Act of June 10, 1920, and it requires that the Commission license any non-federal hydroelectric project which is located on federal land, or located in and uses water from a navigable stream, or uses water impounded by a federal dam. I think most of you agree that considering the tests that the Federal Power Act has been put to over the years, that it does remain Congress's most comprehensive regulation in the hydropower development field. Changes in our regulations to date, involve eight major areas, such as, the short form licenses for minor projects; procedural changes for processing preliminary permits; changes in general filing requirements for evaluating applications for permits and licenses; simplified regulations for major projects at existing dams; regulations for conduit hydro facilities; and delegations of authority to the technical staff. We find the latter particularly helpful in that processing preliminary permits, with no competition as well as those with competition, without rigorous environmental problems and policy questions associated with the application, can be decided without going to the Commission. This reduces the Commission's workload and is done on a staff basis thereby allowing us to process permit applications quite a bit faster.

The other areas include exemptions for small hydroelectric power projects of 5 megawatts or less, the case-by-case 5 megawatt exemption procedure; and lastly, the dam safety regulations which were issued earlier this year by the Commission. It's important to remember that these changes and changes that will occur in the future are designed to make the regulations more understandable. Obviously there are many nuances to any type of hydropower facility; words have different interpretations, therefore we encourage your continual contact with us when there is a question in preparing an application. I know that a number of you in this room have done so, and we think that's an important part of our job, we want to assist.

Generally, there's been about an 80% reduction in the sheer volume of words associated with these major areas of regulation simplification that I've talked about. The problem areas I'd like to dwell on, and you may have some questions associated with this subject, relate to preliminary permits and competition.

As was noted by earlier speakers -- we've reached no decision yet on the hybrid application. Now, I believe most of you understand what the hybrid application is, but for those of you I didn't see earlier today or may have arrived this afternoon we're talking about a joint venture between a municipality and a private organization. The hybrid application then may or may not involve 7(a) preference under the Federal Power Act. In other words, municipal preference. This issue is being considered by the Commission. As most of you know, there was a notice of inquiry issued in February of this year, asking for comments, and the comment period closed in early April. The question was raised then, how should the hybrid be handled? Comments range from, grant the hybrid municipal preference to don't grant the hybrid municipal preference. We received considerable comment on both sides of the issue, and it has not yet been decided. So we feel, from a staff point of view, that something needs to be done soon because of the backlog that I mentioned. We can reduce it considerably when the hybrid issue is answered by the Commission.

As a number of you have discussed -- so I know that there's some familiarity with the firms in the country that are developing joint ventures with municipalities - a percentage of the net revenue is offered to municipalities if they will file a hybrid-type application. Others are using a fixed-sum arrangement with municipalities in the hope that the hybrid application will receive 7(a) preference. There has been a great deal of concern with regard to that method of doing business.

The other problem worth mentioning is a serious one to us and I think to you in that it involves time in processing applications; the matter of competition. Do you realize that we had 18 filings for one site on the Mississippi? I recall a case in California which involved a government dam. The issue of competition between two municipalities resulted in a delay of granting the license close to two years. The law firms of the two applicants continued to do battle by interrogatories to the Commission, issues which had to be addressed, and this is a problem in the goal of licensing as quickly as possible when we have a two-year delay on a significant project.

If we figure an additional cost of 1% a month, roughly, as an inflation factor, we realize what's happening to the viability of a project. The issue of competition creates a problem for us and a problem for you. Incidentally, in this particular case it was quite interesting in that earlier we talked about minimum flows. In this case...a Bureau of Reclamation dam, Monticello Dam near Napa, California, when the project was completed in 1957, the minimum flow was 10 cubic feet per second. During the review of the license application, the State Department of Fish and Game had recommended a minimum flow of 30 feet per second. Yet, the Department of Fish and Game provided no rationale for 30, indicating the benefit of enhancement to local fishery. This can certainly affect the net revenue of the project. The way the issue was handled was that there was no rationale given for the additional minimum flow associated with an increase in fish mortality. In addition, this was a federal project where a minimum flow was authorized by another piece of legislation. Therefore, at sometime in the future when it becomes apparent that additional flow

may be necessary, then it would be a matter of negotiation between the licensee and the State of California. In essence, what happened because of the decision, the project was licensed and not delayed for another two years or so in order to undertake studies to evaluate whether the additional minimum flow was necessary. We are continually going through these types of evaluations, the end result being the goal to get licenses issued as soon as possible.

With regard to 7(a) preference under the Act where we have public versus private development, a "muni" may simply Xerox the private's application. We've seen instances of this. If a filing involves two "muni's" (two municipals), first in time receives the license or the preliminary permit application, all else being equal -- by all else being equal we mean, "Are the projects equally adaptable?" Of course the same thing would apply if we had two private developers filing for one site: first in time would apply.

Another problem -- and this, Bill just brought up -- is, does the municipal have the authority to be in the power business? Particularly, being in the power business in another state. We, as you know, are questioning whether such authority exists. Does the municipal have this authority? If it does not, then there would be no preference. Let's say where an association of municipals in the State of Virginia files at sites in West Virginia, Kentucky, and Pennsylvania. The question arises, do they have the authority to be in the power business in those states? The matter is currently under consideration.

I believe, too, that you can appreciate with the large number of preliminary permit applications that we are receiving, all of us that have been in the power business for many years -- I've been in it for over 25 years, there is a strong desire to process filings, however, 1800 preliminary permit applications by the end of fiscal year 1981 -- that's alot!! It may be 2000, just wait a month! We're getting about 130 a month. So, we have to take a hard line on applications, particularly those that are competing. If these applications don't comply with our regulations, we're going to reject them. Now, having said that, if there's some uncertainty, the time to evaluate or clarify issues would be in the preparation of your application. Call us. Contact us, and we'll work with you at that time. We simply don't have the time to nurse an application through, as was done some years ago. Simply, the volume of business doesn't allow us to do that anymore. We just don't have the people to do it. So, please call us early when you need clarification. We want to help you and we will!

With regard to legislation, we belive there will be legislation of the one-stop type. We believe it will be introduced fairly soon to get around the difficulties, discussed earlier, of duplicative federal permit and licensing authority and also may even involve a preemption at the state level, but primarily at the Federal level. The Federal Energy Regulatory Commission and its predecessor agency, the Federal Power Commission, always considered that it had authority to have access to a site when a license was granted. You heard earlier, correctly, that once a license is granted the right of eminent domain exists under Section 21. Having said that, what about the Federal Land Management Policy Act, where Federal lands are involved? The Bureau of Land Management -- and this is in litigation now -- is interpreting that a certificate should be issued by the Bureau of Land Management of the Department of the Interior. It simply is another piece of paper. And how many more extra

pieces of paper do any of us need? We should really reduce the paper burden and we may get some more! In the environmental area, a number of duplications exist such as Section 404 of the Water Quality Act permits. So we believe that one-stop-type legislation will be introduced saying that the Federal Energy Regulatory Commission would be the lead agency according to the Federal Power Act as it has been interpreted over the years.

Also we expect that legislation will be introduced raising the exemption level to 15 megawatts, in cases where there are no environmental or other constraints. This could also eliminate the 7(a) municipal preference. The legislation could take the form of a waiver, meaning that certain parts of the Act may be waived. But if it were a complete exemption, then we could see that 7(a) would not apply because there would be no license associated with a project of 15 megawatts or less.

Along with such exemption authority, as I mentioned just a bit ago, there may be the right of preemption whereby there could be some change relative to not only Federal but requirements at the state level. This remains to be seen regarding how the legislation takes shape. In fact, if I'm not mistaken, it's being discussed on the Hill today with congressional staff. Future actions by the Commission may involve requirements associated with it such as taking the form of the 5 megawatt case-by-case exemption, where ownership or property interest is required for a site and the application must indicate an increase in capacity up to 15 megawatts, as in the current case-by-case procedure.

If you have a 1 megawatt plant and you file for an exemption of up to 5 megawatts this calls for additional generation. In these cases, municipal preference doesn't apply, and if the Commission doesn't act within 120 days of the notice date when the exemption application was accepted, it would be automatically granted. I'm not saying that 120 days would still apply to the new exemption legislation. It could be a shorter period of time. A shorter time is being considered in the generic 5 megawatt or less exemption. We're receiving quite a few calls about that, and we've had public hearings on it. That exemption, the generic exemption, does assume certain constraints, particularly those involving the environment, such as no significant upstream or downstream passage of fish; will not violate applicable water quality standards; in addition, it does not divert water more than 300 feet from the toe of the dam. Of course the generic exemption cannot involve a government dam just as the 5 megawatt case-by-case exemption cannot involve a government dam because of ownership; you must have property interests or own the dam in order to receive the exemption. Also the generic exemption would only apply to an existing dam. In the proposed rule, a 30-day period of time after the notice has been accepted an automatic process will most likely by involved granting the exemption, note we must have a notification. Obviously, in these cases involving a generic exemption, you need the notification in case someone would file for that particular site where we have granted an exemption. We need some paper to know that there is an operating project there. Integral with the generic exemption there may be a programmatic type of environmental impact statement defining the environmental constraints.

Also, we expect that the short form license applicability will be stepped up to 5 megawatts; therefore, the abbreviated application regulations will apply to all projects with an installated capacity of 5 megawatts or less.

Lastly, changes are being considered regarding the requirements for preliminary permits and license applications requiring evidence of authority and competence for a municipality to be in the power business, as I mentioned earlier. Clarification is expected placing some certainty on the issues of amending an application materially whereby the amending applicant will lose priority status relative to competing applications. We have some cases along this line, and it isn't clear what will be or should be done with them. Whether we will continue to issue preliminary permits at all is also being looked at. I don't have time to get into some areas that I've discussed during breaks and lunch, such as memoranda of understanding that the Federal Energy Regulatory Commission is developing with the Bureau of Reclamation, and the Corps of Engineers. Some of you will recall that there have been problems of turf when applicants file at government dams. If you have some questions associated with that, I'd be glad to answer them. The issue of annual charges is being considered; I haven't discussed that, however, I'd be willing to undertake any questions.

So, if you want to ask questions about these subjects and those that I've covered, feel free to do so. I only noticed about 2% of you falling asleep, so I guess I'll give you a grade of 3.9 on a 4.0 system -- sounds pretty good at this late stage of the afternoon. Thank you for being so attentive. Let's have a few questions.

Q. When will the 15MW bill be in the legislative mill?

A. Well, the legislative package hasn't actually reached the Hill yet, as I understand. If you were to ask me this question two days ago, I would simply say, "No, I don't know". But I accidentally found out yesterday it hadn't reached the Hill yet. They're talking about it today. Staff, clerks of the committees of jurisdiction, are considering it. So I have no idea; when it will reach the Hill. I'm sure that most of you will know when it does. It will be in all of the newsletters once it has a number. And then, of course, we just have to wait and see when it's placed on the calendar, the respective calendars of both houses of Congress.

EQUIPMENT SELECTION FOR OPTIMUM POWER

By

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INTRODUCTION

Optimum power or annual energy may be defined as the quantity of energy that a hydro-turbine will produce at a given site over a period of one year when operating within the generating units constraints. Figure #1. It is a function of the site head and flow available. It is influenced by the elevation of the machine and the tailwater elevation at the site as a function of head and flow. Parameters such as turbine size as defined by runner diameter and operational speed are also significant in determining the annual energy output. Other factors involve the turbine setting, planned usage of the unit, power outputs desired, reservoir capacities, whether the unit will be isolated and remotely controlled or manually controlled.

Where wide variations in flow, head and tailwater are normally experienced, the annual energy calculations are extremely valuable in determining the proper combination of parameters to optimize plant income and investment.

REQUIRED DATA

The information required for the application and selection of hydraulic turbines will vary depending upon the degree of accuracy of the information desired. If only head and flow are known or are provided, a turbine size may be selected, however, its setting with respect to tailwater elevation must be arbitrarily defined. Usually such an inquiry will result in a relatively high estimate.

More accurate selection and application requires detailed, specific information. Manufacturers can provide accurate equipment selection and sizing and will provide this information without charge as a means of their defining potential markets. To prepare a complete proposal promptly, it is important to provide the following data, where applicable and available:

1. A name of the firm or corporation and individual with address and preferably phone number in order to provide a reply and/or obtain additional information.

2. Location and name of the plant or dam site. Most inquiries are cross-referenced by project name and frequently additional infor-

* See page 61 for Biographical sketch

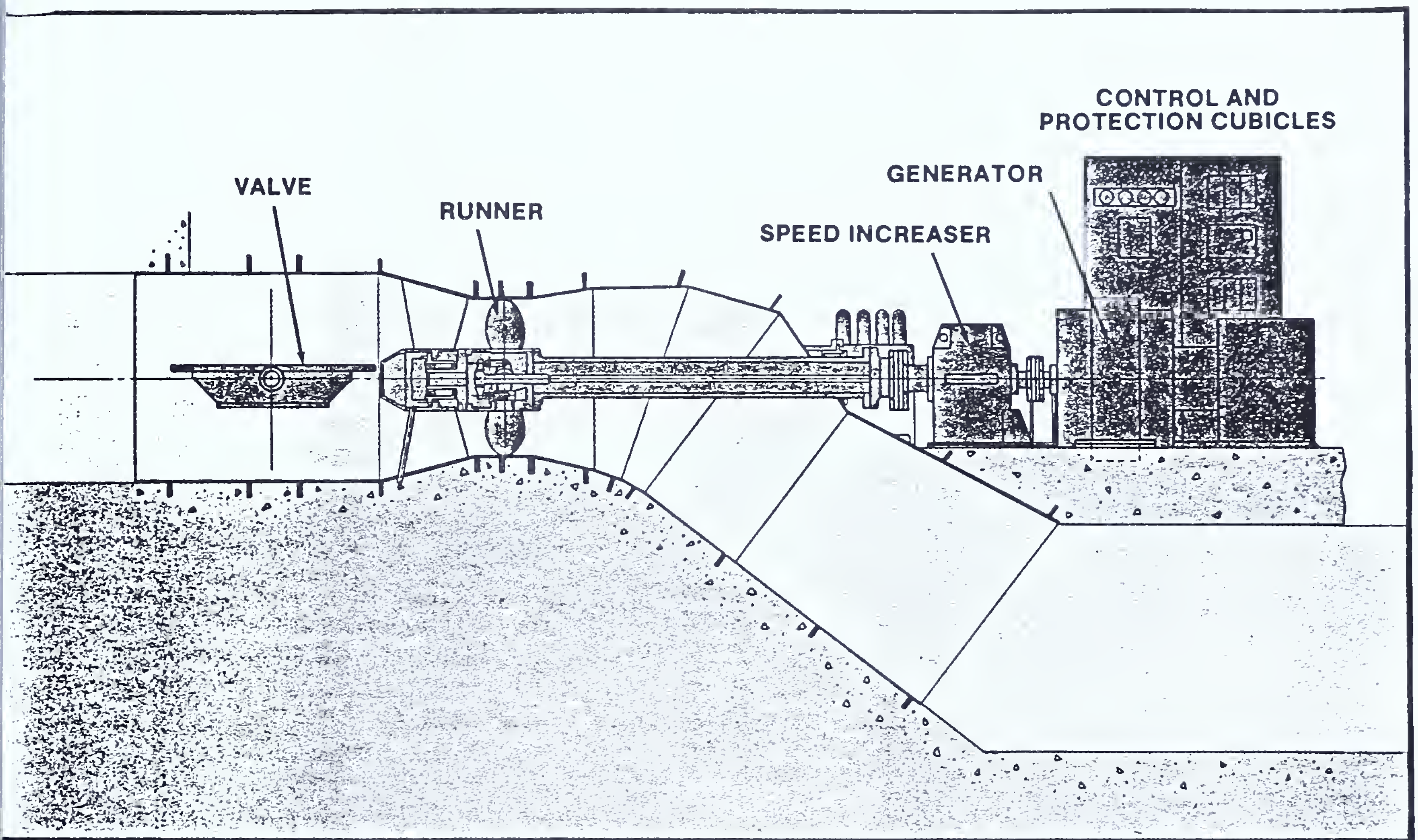

CONTROL AND
PROTECTION CUBICLES
GENERATOR
VALVE
RUNNER
SPEED INCREASER

Figure 1

mation is available on specific sites. If an old plant is involved, drawings of the original equipment will usually be filed under the purchaser's name and occasionaly under plant name.

3. Approximate elevation of the plant above sea level is needed to obtain barometric pressure which is used in establishing the cavitation limits and can also be significant in establishing generator cooling requirements.

4. Total quantity of water is required preferably in the form of a flow duration curve corrected for the drainage area at the particular site involved. The shape of the flow duration curve can have a substantial effect upon not only the size of equipment, but also the number of units that may be selected.

5. The quality of the water becomes important primarily from the standpoint of erosion and whether or not the water is suitable for bearing lubrication. Corrosive water can substantially accelerate pitting damage caused by cavitation.

6. Gross head becomes important from the standpoint of mechanical design of the hardware. Also, correlated head duration and tailwater elevation duration curves are important. A wide variation in head will influence the equipment type and a wide variation in tailwater elevation may necessitate a submerged or waterproof powerhouse or a vertical turbine shaft arrangement.

7. The net effective head is the basis of all turbine power guarantees and is basically the responsibility of the equipment purchaser or his consulting engineer. This will be estimated by the turbine manufacturer if not specified.

8. The amount of power desired or required may only be significant if it is only a very small part of that available or is substantially greater than that available.

9. Discharge or load at which maximum efficiency is desired becomes important primarily when it is not consistent with conventional turbine efficiency curves. It may be necessary or desirable to oversize or undersize the turbine or adjust the number of units.

10. The number and size of the units contemplated or required, now and for future installation, may only relate to existing structures. On the other hand, if the project schedule is to be compatible with a load schedule, this may be significant. It is extremely important in order to minimize civil construction costs that complete information be provided concerning any given space limitations as well as details of existing foundations and superstructures. Existing crane capacities may limit the size of pieces as well as the installation schedule. Existing foundations may substantially reduce the civil construction costs or may be a substantial hindrance to the most economical development of a particular site.

11. The distance from normal tailwater levels to the powerhouse floor as well as correlated information with respect to tailwater elevations becomes particularly important when selecting the type turbine if the floor elevations will affect the location of the turbine with respect to tailwater. While a propeller type turbine would normally be used for low heads, it may be necessary to use a Francis type turbine if the runner must be set at a substantial distance above tailwater. Existing powerhouse floor elevations may influence access to the turbine.

    Also, the cross sectional area and length of the tailrace will influence tailwater elevations and they may become a limitation on the plant capacity.

12. The proposed length, diameter and material of the supply pipe (penstock) if required or if existing. This becomes very important from a head loss standpoint as well as water hammer and speed regulation considertions. As a rule-of-thumb, if the water passageway length exceeds three times the head, it becomes particularly important to investigate water hammer and speed regulation. The penstock or tunnel material will affect the velocity at which a pressure wave travels, therefore, will affect the water hammer calculations.

13. If a surge tank is installed or contemplated on the pipeline, the distance along the penstock and the surge tank data become vital to water hammer and speed regulation calculations.

14. Whether or not the plant operates separately or in parallel with an existing power system, will also affect speed regulation characteristics and the type of generator that may be used. If there are any particularly large motors to be started or severe load changes to be accommodated, these also will make a substantial difference with respect to the equipment supplied. In some cases it may be necessary to add a fly wheel to the equipment if it is not tied into a system and rather substantial load changes are expected.

15. The intended method of operation becomes important in selecting the control system. Hydro units may be operated manually, semi-automatically, or fully automatically and may also have remote controls. For most small plants it is not practical to have a fully manned, manual plant. A governor to control generator frequency usually is not necessary particularly if the unit is tied into a large system. Many of the small installations may be most economically operated from head water level control with automatic shut-down in emergencies and manual start-up so that in event of shut-down, an individual must visit the plant to make sure it is in proper working order before start-up.

16. Supplementary information with drawings or sketches are of substantial assistance in interpreting specific site situations. Topo-

graphical survey maps help provide precise location and in many cases will identify transmission lines, gauging station locations, potential loads, access, interference with roadways and railroads, etc. Drawings and photographs of existing structures most easily communicate the potential interference or benefits of using such structures. Even a sketch relating the dam location to proposed powerhouse location, river bed and flood plane can be of substantial assistance in identifying factors that can influence the turbine selection.

ANNUAL ENERGY OUTPUT

Primary data required for conducting an annual energy study include flow as a function of time through the plant, head and tailwater elevations as a function of that flow or as a function of time. Figure #2. In addition, the operational characteristics of the plant are required to be able to mathematically describe the plant model.

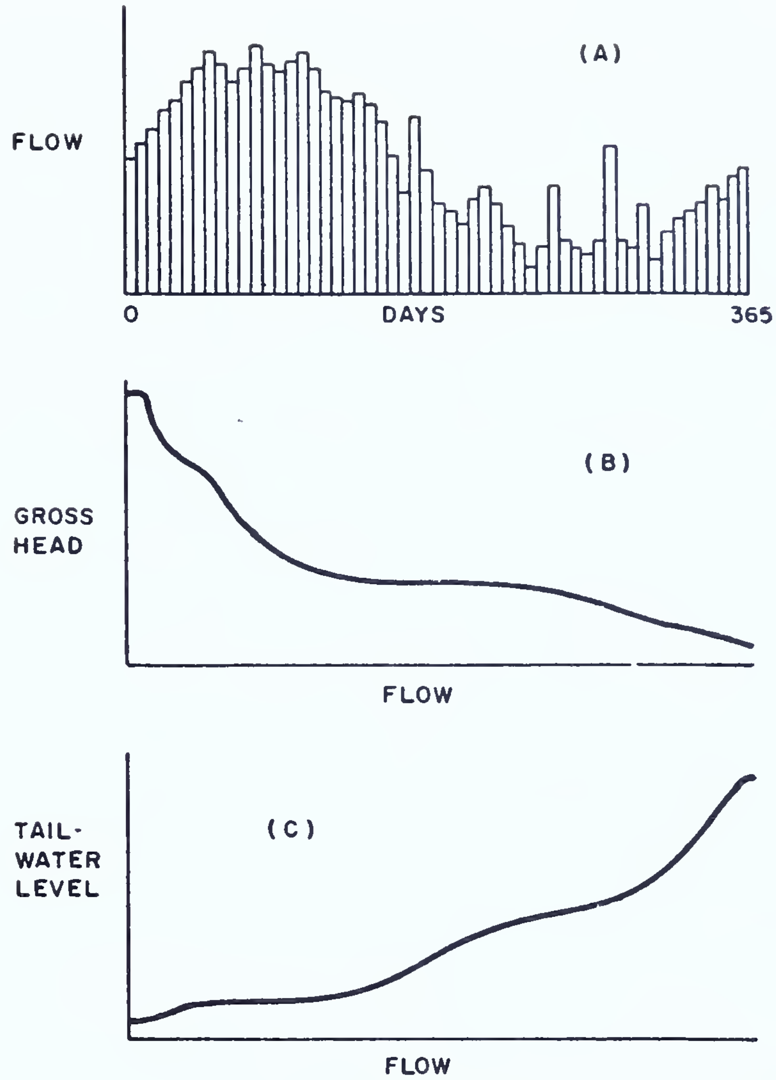
Secondary data such as water loss due to leakage and process water used will influence total flow available. The net flow available for energy production must be established. An analysis of the flow conditions must be made to identify head losses which are characteristic of the plant site but not normally considered as part of the turbine. Such losses would involve intake trash rack and penstock losses. The ponding capacity at the site must be considered in light of the operating philosophy. If ponding is allowed, the ponding volume and head range must be established. The ponding schedule must be known so that better utilization of the turbine performance can be made.

To be able to evaluate the revenue production and the cost of the installation, dollar values must be assigned to the energy produced. Costs of construction and how it is influenced by machine size is required. Cost of excavation must be established to be able to evaluate the additional energy produced for deeper unit settings. Equipment cost as a function of size and speed are significant factors in the overall economic analysis. Figure #3.

Based on the input data, options are chosen within the annual energy model to provide for calculation of the energy output as a function of the number of turbines, the turbine unit size, the setting, the speed, and other parameters that vary. On a cost basis an evaluation of the results is made and a set of parameters characterizing the turbine are chosen to produce the most economical solution or the most cost effective solution for the project.

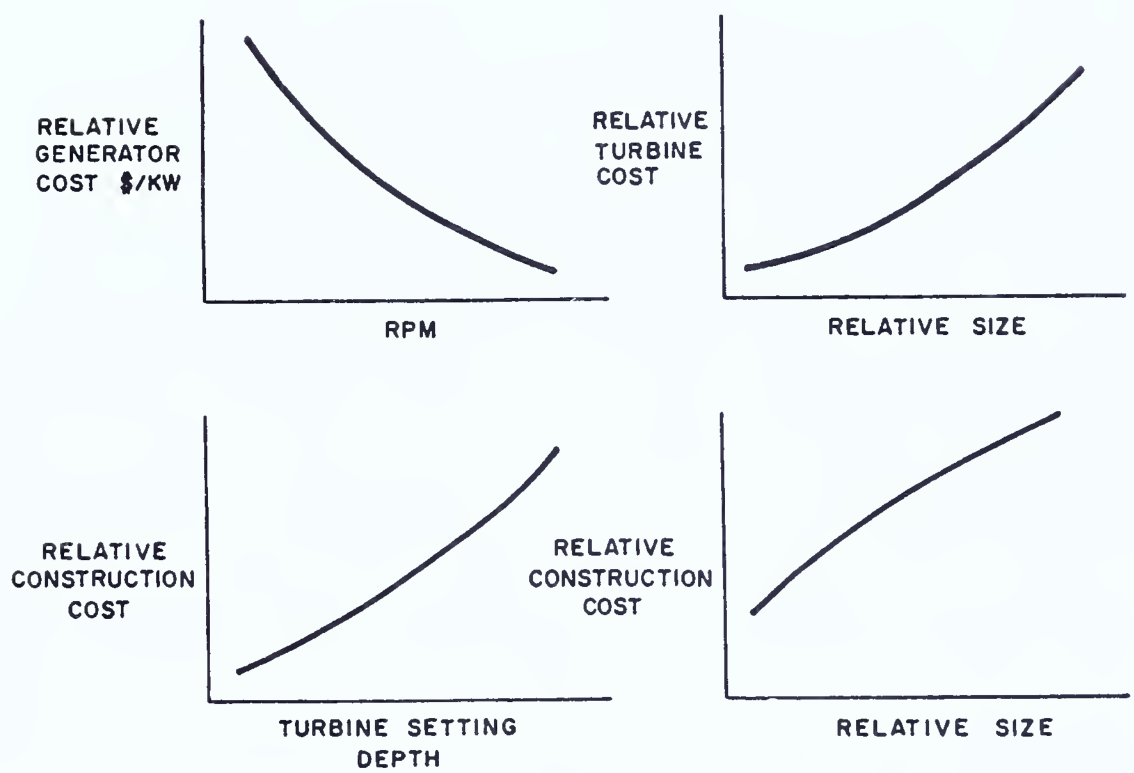
SITE HYDROLOGY

The simplest annual energy model can be based on condensed U.S.G.S. data. Daily flow observations over a period of years provides the basis for a flow duration curve. Figure #4. A preliminary annual energy output from a site can be predicted utilizing this information.



Primary Site Characteristics Required to Calculate Annual Energy

Figure 2



Costs Associated with Turbine Parameters

Figure 3

A next level of sophistication is reached when the entire flow survey is broken down into monthly mean (Figure #5) and standard deviation statistics. However, this technique still lumps all flows occurring within a given month and represents some smoothing of the data.

SITE PHYSICAL CHARACTERISTICS

Once the flow data is available for a particular site, the site physical characteristics can be incorporated to determine the headwater and tailwater available as a function of flow using standard techniques. Reservoir capacity as a function of reservoir upper level is required to assess the effect of ponding of the annual energy production.

HYDRAULIC TURBINE CHARACTERISTICS

Turbine performance characteristics are required to predict annual energy. This performance data is determined through extensive model tests. Efficiency, flow and power as a function of head and operating speed are typically determined, calculated, and non-dimensionalized into performance coefficients and summarized on a turbine performance hill curve. Figure #6. Within the performance map of the turbine, limits to operation exist.

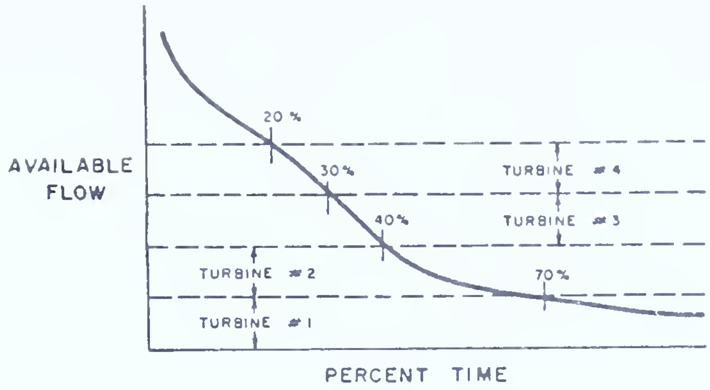
The most important of these limits is cavitation. The cavitation limit is a function of tailwater elevation, turbine setting with respect to tailwater and flow through the turbine. At the cavitation limit, (Figure #7) the turbine is operating at maximum flow possible before cavitation begins to adversely affect performance. Operating at higher flows will result in a significant reduction in efficiency can result in damage to the turbine water passageway components because of pitting damage, and will result in excessive noise and vibration.

Maximum gate opening or blade angle results in a maximum power limit. Figure #8. This occurs where, at a given head coefficient, a value of power is reached which cannot be exceeded.

Another limit is minimum efficiency. Figure #9. This is a qualitative limit. Operation at efficiencies below those nominally set as minimum may be associated with high levels of noise and vibration.

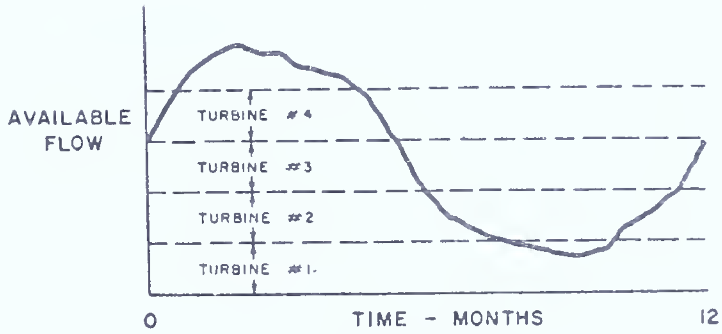
PLANT SIZING AND SPEED SELECTION

Consider a series of annual energy calculations utilizing a range of unit speeds, turbine sizes, and turbine settings. With the cost of machinery, civil costs, and energy value, the plant economics can be calculated. These economics will provide information leading to the optimum size for the turbine and the plant site to provide the maximum return on investment. Figure #10. The results of a large number of annual energy calculations utilizing various parameters are illustrated. Along lines of constant speed, turbines of various sizes are evaluated and the annual energy outputs are calculated and plotted versus turbine diameter. These sets of evaluations are repeated at several speeds.



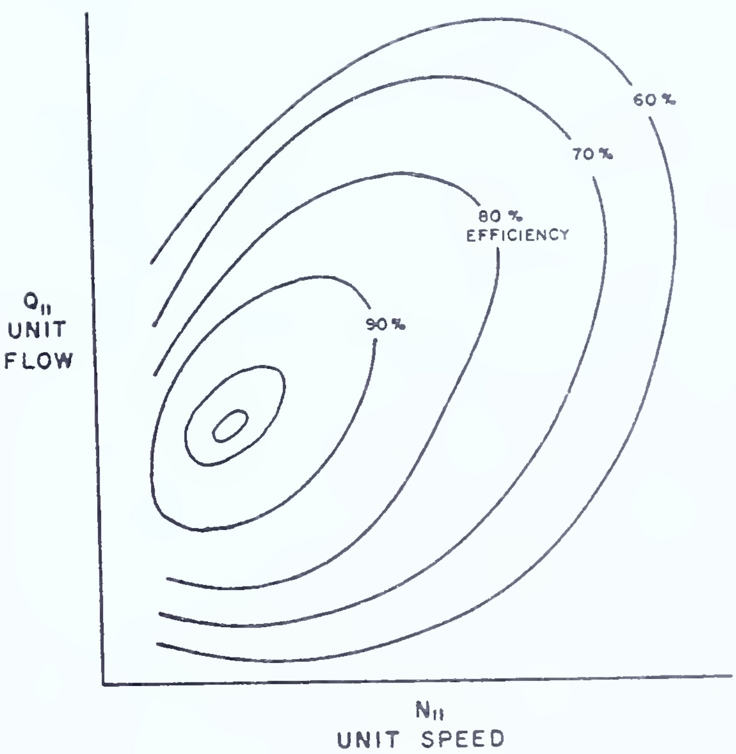
Typical Presentation of Flow Duration Data

Figure 4



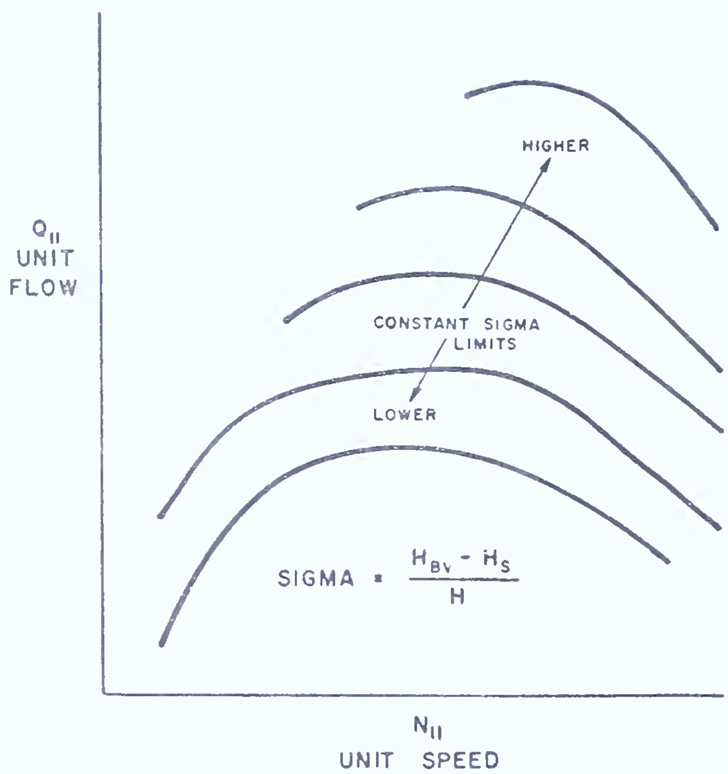
Monthly Average Flows at Site

Figure 5



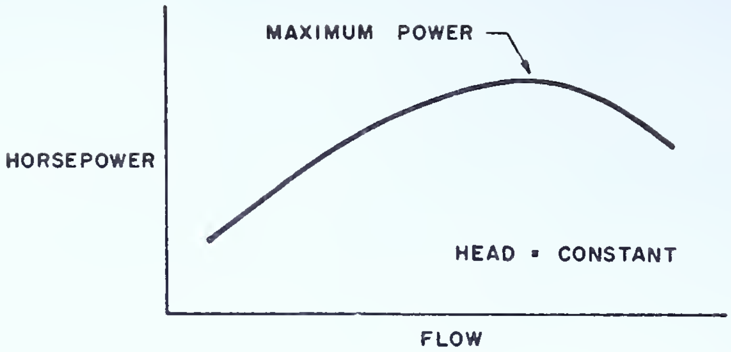
Turbine Performance Characteristics Summarized In Coefficient Form

Figure 6



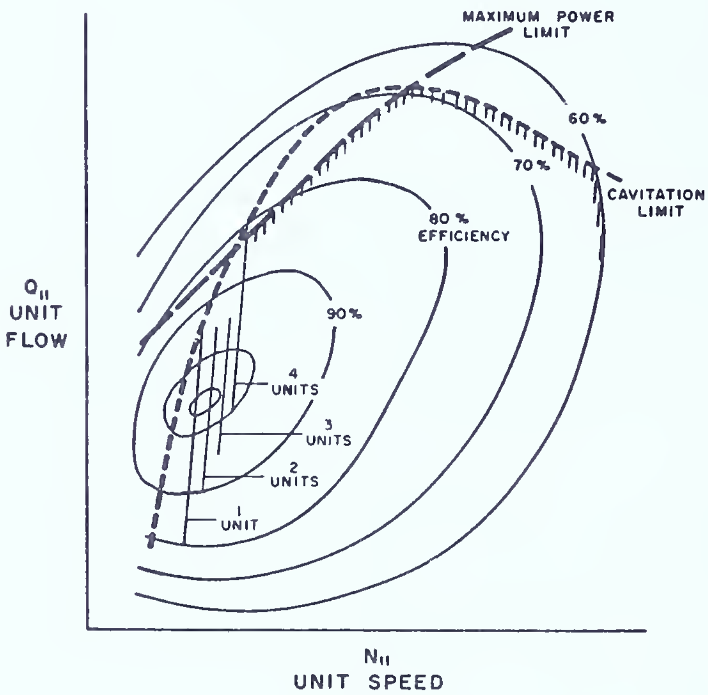
Turbine Cavitation Limits as a Function of Sigma

Figure 7



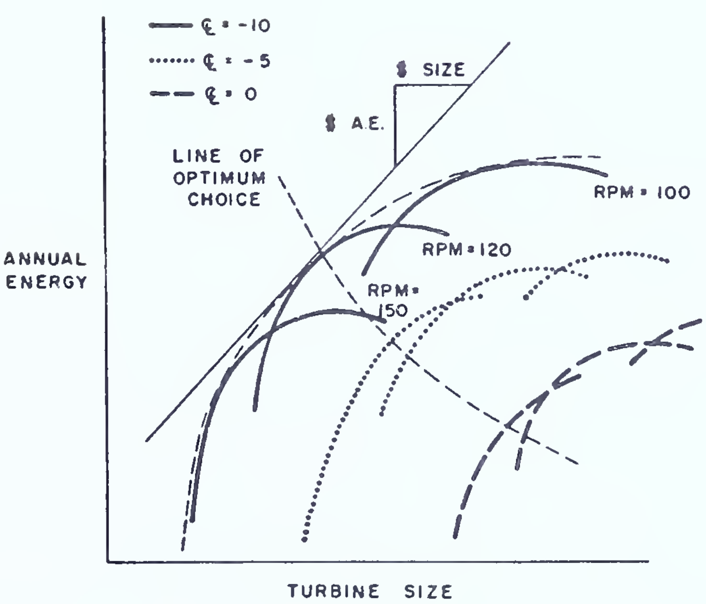
Turbine Horsepower Output as a Function of Discharge

Figure 8



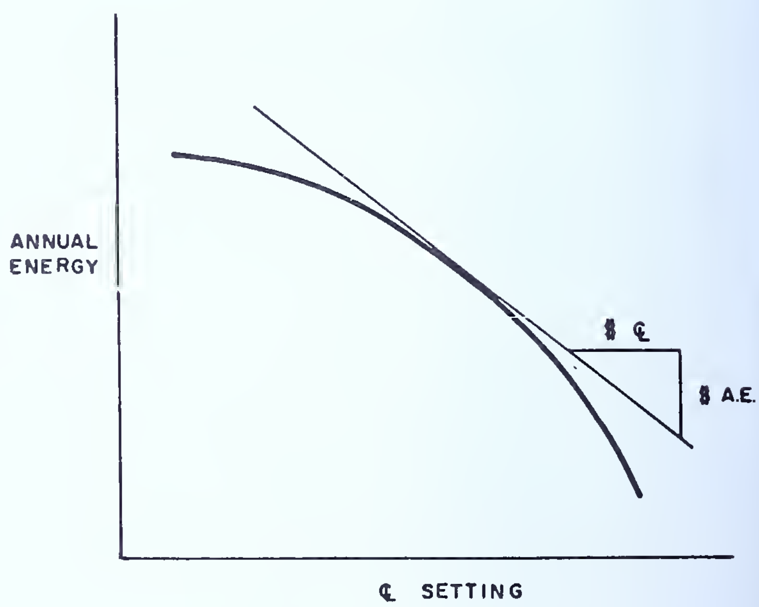
Turbine Operational Regime

Figure 9



Annual Energy Evaluation of Turbine Parameters

Figure 10



Turbine Setting Selection Based on Annual Energy Concepts

Figure 11

Knowing the functional relationships between the value of energy and the cost of the plant for a turbine of a given size, a selection of the optimum size and speed can be obtained. This evaluation is repeated at several settings. The results are plotted in terms of annual energy as a function of centerline location and the value of annual energy produced is compared to the additional expense of excavating to obtain that energy. Figure #11. This size, setting, and speed will then represent the optimum selection of turbine parameters to maximize the return on investment.

CONCLUSIONS

The annual energy calculation technique is a powerful tool for the parametric evaluation of turbine performance, size, speed, and setting to determine the optimum combination of variables to maximize the return on investment. Effects of varying the turbine parameters can be readily determined and the worth of such variations evaluated. Through the use of automatic annual energy calculation techniques rapid determination of plant sizes can be made. As with all tools, the validity of the results depends directly on the validity of the information available to make the annual energy evaluation.

With careful prepartion of the input and consideration of all primary variables, accurate annual energy evaluations can be made and valid conclusions can be drawn.

HOWARD A. MAYO, JR., P.E.

Biographical Sketch

Mr. Mayo received a BSME degree from Worcester Polytechnic Institute in Massachusetts. He holds several U.S. and foreign patents relating to hydraulic machinery, has presented numerous technical papers, and has contributed to several text books on the subject of hydraulic machinery. He is a member of the American Society of Mechanical Engineers and is a registered Professional Engineer.

Mr. Mayo is responsible for the development of Standard Products and Customer Service markets. Standard Products include small and standard hydroelectric units, Bascule gates and Howell-Bunger valves. Customer Service includes repair parts, modernization and rebuilding of hydro-turbines and related products.

During his more than 30 years of service, Mr. Mayo has served in engineering and marketing positions. He has developed and promoted the TUBE unit as an economical equipment design for low head hydro electric sites. He has been intimately involved in the engineering and application of both conventional and reversible hydroelectric equipment in the United States and abroad.

CONSTRUCTION APPROACH TO CURRENT HYDROPOWER PROJECTS

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Mr. Lasch graduated from the University of Virginia in 1979 (BS and ME - Civil Engineering). His professional affiliations include the American Society of Civil Engineers, the National Society of Professional Engineers and the Pennsylvania Society of Professional Engineers.

Mr. Lasch is a project engineer in the Water Resources Engineering Department at Michael Baker, Jr., Inc. He presently is responsible for identifying and developing dam sites throughout the Eastern United States which have hydroelectric potential. His work includes initial site reconnaissance, preparation of Federal Energy Regulatory Commission preliminary permits and Department of Energy loan applications, and performing feasibility studies.

Since joining the company, Mr. Lasch has inspected more than 70 dams in Pennsylvania and Virginia under the National Dam Safety Inspection Program. In this program, he has been responsible for conducting field inspections, hydrologic and hydraulic analyses, structural analyses, and for making recommendations for repairs and modifications required at each site.

INTRODUCTION

Successful development of the hydroelectric potential at existing dams involves solving a multitude of difficult technical problems. The solutions to many of these problems are simplified to some extent by the fact that the technology of hydroelectric projects is a relatively well-established field with a large body of information and experience to which an engineer can refer. However, there are still several important aspects of the recent trend toward developing small-scale, low-head sites which require new levels of engineering expertise and other skills before projects can be brought to fruition. These include:

1. Limited Current Engineering Experience - Even with the recent demonstration projects sponsored by the Department of Energy, there are only a small number of engineering firms which have current experience in designing hydroelectric facilities. A majority of the more recent experience has been with large-scale sites. Engineering approaches which may be the best for large-scale projects are not, generally, the most efficient means for solving the problems faced at the smaller sites, especially when trying to retrofit a site to produce power. Perhaps the single largest engineering challenge faced at these projects is to, in a cost-effective manner, develop a plant design for a site which was never, in all likelihood, intended to produce power.

2. Limited Equipment Experience - As with engineering experience, there are very few manufacturers who have long-term experience in low head and/or low flow turbine units. The majority of units which are currently available do not have the type of long-term operation and maintenance records which are desirable when designing a plant which will, hopefully, have a lifetime of 25 - 50 years.

Both of these two problems can be overcome with careful project planning, coordination of all study phases, and thorough investigation in the proposed plant equipment. But there are at least two more important factors relevant to projects today which are more difficult to include in project planning. Namely:

1. Complications in the Permitting and Licensing Processes - The Federal Energy Regulatory Commission is working diligently to simplify and speed up these processes. However, there are various potential site developers who are working just as hard to find new loopholes in the regulatory process and who are, in effect, creating further complications and delays in the granting of permits. This has become an especially large problem with the types of maneuverings which have been made by some developers in competing permit situations. Competition in many instances consists primarily of private companies which are apparently looking at the permit process as a type of "lottery", i.e., the more permits they apply for, the better their chances are of receiving a permit. Unfortunately, there is no quick way to deal with this problem or plan for the delays which are created by spurious applications such as these.

2. Changing Market Conditions - The constant fluctuation in the prime interest rate, rising inflation, uncertainties in the value of power, and other economic factors have a strong influence on the ultimate feasibility of site development. Therefore, during all phases of project development, the current and projected economic trends must be considered an integral part of project planning.

The point of the foregoing discussion has been to illustrate that overcoming technical problems is but one of the many obstacles to project completion. Expert legal, financial, and engineering services are generally required to successfully build most small-scale, low-head projects. If these services are retained prior to beginning the initial stages of a hydropower project, the problems and delays mentioned above can be overcome, or at least minimized.

CURRENT PROJECTS

The three sites which will be discussed are located on the Beaver River in western Pennsylvania. These three dams include some of the typical problems and types of design situations which might be encountered in small-scale low-head hydropower projects.

The overall design problems at these sites are extremely similar in that they all have the following characteristics:

1. All three dams were built in the 1850's to early 1900's.

2. All three dams were constructed using rock filled timber cribs.

3. There are some existing hydropower facilities at each site.

4. All three dams lie within a 2.5 mile reach of the Beaver River with no significant tributaries entering along the reach.

5. There is no significant storage at any of the sites.

Therefore, the following questions must be answered at each site:

1. Are the structures, given their age and type of construction, sufficiently sound to survive the projected lifetime of the proposed projects?

2. Will maintenance over the lifetime of the proposed projects be a significant problem?

3. Is it feasible to use the existing hydropower facilities or are completely new facilities required?

The approaches and philosophies being employed to solve the problems in these cases will be used to illustrate problem-solving techniques which have proven to be cost effective.

1. Eastvale Dam - The Eastvale Dam was originally constructed in 1891 using rock filled timber cribs. In 1925, the dam was rehabilitated through the addition of a concrete apron to the downstream face of the dam. The dam is approximately 500 feet long and has an available head of 12.6 feet. Visual inspections recently performed indicate that, aside from some minor deterioration, the dam is in good condition.

   At the east abutment of the dam, slightly upstream from the crest of the dam, are 10 headgates which control flow into a headrace channel. The headrace carries water to the pumphouse for the water treatment plant located at the dam. There are five, masonry-lined channels leading into the pumphouse; flow in each channel is controlled by a gate located at the upstream entrance to the building. One of these channels supplies raw water to the treatment plant; the remaining four channels were constructed to carry water to turbine shafts. Currently, there is one active turbine which is used to mechanically drive a pump which supplies a small portion of the finished water pumping capacity of the treatment plant. Two of the turbine shafts contain turbines which are in need of repair. The channel leading to the fourth turbine shaft has been sealed with concrete. Water is discharged from the turbine shafts directly to the Beaver River.

Fortunately, a good set of construction plans for the dam and appurtenant facilities were available from the Municipal Authority which owns the dam. These plans were invaluable in the initial evaluation of the site and will be used as base mapping for the final site design.

After reconnaissance level estimates of the potential power output of the site, power value, and cost of facilities were completed, detailed studies were performed in the following order:

a. Structural Stability Assessment - Using the available information for the dam, a relatively detailed structural evaluation was performed. This was based on conservative assumptions regarding the physical conditions and makeup of the structure as well as the various operating conditions which are anticipated at the site. This analysis indicated the dam was in an acceptably stable condition. If the analysis had indicated unsatisfactory levels of stability, further procedures would have been initiated which would have combined detailed investigation of the structure with repair measures. In other words, no stability studies would have been made which did not, as a primary objective, include methods for ensuring the continued stability of the dam.

b. Assessment of Existing Hydropower Facilities - Approximation techniques were used to estimate the performance characteristics of the existing facilities. Comparison of these characteristics with the optimal characteristics as defined in the reconnaissance level study indicated that there is a significant difference between the capabilities of the existing facilities and those required to produce the total site potential. This difference calls for consideration of at least three development options:

    (1) Restore existing equipment and generate power at a level below the site's potential but at a lower initial cost.

    (2) Restore and supplement the existing equipment with new equipment.

    (3) Install all new equipment and perhaps stage equipment installation to spread out the higher initial costs.

    Currently this project is at this level of the overall study. The overall power needs, financial condition, and ultimate goals of the client are being used to expand on these options and select a final project pattern.

2. Patterson Dam - The Patterson Dam was constructed in the early to mid 1820's using rock filled timber cribs. The dam is approximately 700 feet long and has an available head of 19.2 feet. There are nine randomly spaced buttresses along the downstream face of the dam. The buttresses were constructed of stone masonry and are faced with concrete along their top surfaces. The dam has also been faced with concrete. The concrete facing on the dam has deteriorated in many areas. Overall, the dam is in fair to poor condition.

At the west abutment of the dam, slightly upstream from the crest of the dam, are three headgates which control flow into a forebay channel approximately 500 feet long. There are two powerhouses located along this channel. The first is approximately 60 feet downstream from the headgates and contains a single vertical turbine shaft. The turbine in this shaft was installed in 1925 and is reportedly still in an operable condition. The second powerhouse is located at the downstream end of the channel. There is one turbine shaft in this building containing a turbine which is currently inoperable.

Overall, the headgates, forebay channel, and powerhouses are in fair condition.

There are no construction plans or structural information available for the dam. This lack of information combined with the overall poor condition of the dam required that the evaluation of the structural integrity of the dam be performed before additional in-depth analyses were performed.

a. Structural Stability Assessment - A detailed field survey of the dam was performed to determine the physical layout of the dam. During this survey, a closeup inspection of the dam and appurtenant facilities was conducted to identify any significant signs of structural distress. Of particular importance was investigating the center section of the dam which, according to historical information, failed in 1913 and was later rebuilt.

   Using the data collected during the inspection and survey, a conservative analysis of the structural stability of the dam was performed. Even though this analysis indicated that the dam has adequate factors of safety for stability, it was judged advisable to include some additional structural support for the dam. This work will involve the construction of at least two new buttresses along the downstream face of the dam.

   Currently, further studies into the economics of these repair measures are being made. Initial indications are that, even with the added cost, hydroelectric development at this site is still feasible.

3. Townsend Dam - The Townsend Dam was originally constructed in 1867 using rock filled timber cribs. In 1913, a concrete casing was added to the dam. The dam is approximately 450 feet long and has an available head of 17.2 feet.

   At the west abutment of the dam, slightly upstream from the crest of the dam, are three wooden headgates which control flow into what was once a canal. These gates are currently closed and inoperable. The canal has been filled in except for a small portion immediately adjacent to the dam. The remains of a 24-inch diameter penstock also run along the right abutment.

At the east abutment of the dam are the abandoned hydropower facilities once operated by the Beaver Valley Water Company. These facilities consist of five headgates, located slightly upstream from the crest of the dam, a headrace, two buildings which housed turbines, and a tailrace. Currently, the headgates are inoperable, the headrace and tailrace channels are completely filled in, and the turbine shafts are blocked with concrete.

Reasonably complete construction plans were available for this dam from the Municipal Authority which owns the dam. Analysis of the structural stability was, therefore, conducted using the same approach applied to the Eastvale site. However, because of the extremely poor condition of the existing hydropower facilities, no analysis of these facilities was performed. The plant options for this site which are currently being considered consist solely of new equipment which may be installed in phases.

SUMMARY

The fluctuating economic, regulatory, and technological conditions under which small-scale, low-head projects must be developed require that prudent and shrewd engineering judgment be used during all phases of each project. Only through anticipating and planning for these changing circumstances can a project be successfully completed.

As was implied in the three cases discussed, the most successful design approach will be one that:

1. Eliminates unfavorable design alternatives with minimal delays and expenditures.

2. Is extremely flexible in framework in order to adapt to changing development conditions as required.

3. Anticipates to the largest possible degree any barriers to project development.

4. Coordinates wherever possible the various efforts required for project planning, design, and construction.

To date, this approach has proven to be extremely effective in the projects with which Michael Baker, Jr., Inc. has been associated. The problems faced by small-scale, low-head hydroelectric developers must be solved efficiently in order for a project to be developed within developers budgetary and financial constraints.

DEVELOPING A SITE -- ISSUES AND RESOLUTIONS

Peter A. McGrath, President
American Hydro Power Co.

Peter McGrath is President of American Hydro Power Co., a partnership of O'Brien Machinery Co., The conduit and Foundation Corporation, and American Refining Group, Inc. Prior to the formation of American Hydro Power he served as Executive Vice President of American Refining and was involved in corporate development and finance.

Previously he served as Senior Vice President and Group Executive of Southeast National Bank of Pennsylvania and was the executive director of the Chester Group, an economic development organization sponsored by a coalition of private and public sector leadership. McGrath has also served as a consultant on economic and public policy to various federal, state and local government units.

He holds a Ph.D. and M.P.A. from the Kennedy School of Government at Harvard University and a B.S. from Georgeton University's School of Foreign Service.

This paper will address the following issues:

1. What factors should be considered in making a decision on whether to develop a hydro site "in-house" or to turn it over to an outside developer.
2. What factors should be considered in establishing the value of the given site.
3. What are the different methods of structuring payment to the owner of a site.
4. How to determine a fair price for a given site.
5. How to analyze the advantages and disadvantages of public versus private development.

"In-house" Owner versus Outside Developer

The owners of potential hydroelectric sites are confronted with a basic decision: whether or not to develop the site in-house, or to arrange for the site to be developed by a private developer. The advantage to developing the site in-house, of course, is that all of the rewards from development flow directly to the site owner. Prior to making such a decision, site owners should carefully access a variety of factors which will impact on the extent to which they can be successful with their own development plans.

A key task is gathering of the information necessary for development. There is some cost involved in learning about hydroelectric technology, utility rates, government licensing procedures, dam repair and related civil work, and the related financial aspects. Part of this learning process will involve direct expenditure of both time and money on the part of the owner, which may never be recovered if at any point the decision to develop the site is terminated. From the start, the process of developing a site is both a management problem and a financial risk.

Another factor to be considered is the availability of capital. Site owners may determine that the amount of capital necessary to develop the site when compared to the return on investment may not be sufficient to warrant development. This would be the case with industrial firms which may have alternate uses for the capital for projects with higher financial paybacks. Muncipalities on the other hand may find that there are more critical competing uses for their limited borrowing capacity for long-term capital projects.

The alternative to in-house development is to use a private developer. Generally, development costs fall when more than one site is developed. Overhead can be spread over several projects, and after doing the first project learning costs fall rapidly. This is one of the advantages a private developer has, especially with respect to having broader information on financing alternatives, negotiations with utilities, the selection and installation of equipment, and compliance with the numerous governmental agencies involved in the licensing process. The time necessary to complete a project should also be shorter using a private developer, thus the overall cost of development should be lower. Capital would begin earning revenues in a shorter period of time, and thus would yield a higher rate of return.

Ultimately the owner of the site must ask the question, "What business am I in?" There is a trade off between risk and reward and, prior to any decision to develop the site internally, the owner should weigh carefully the total risk involved versus the perceived reward to be gained. The next section covers the key factors which vary from site to site and which determine the value of a site if the owners wish to either sell the site or turn it over to a private developer.

Factors Which Establish the Value of a Specific Site

In the event that a site owner chooses to utilize a private developer, some formula needs to be created to determine the value of the site. There are two major factors which a developer will consider in arriving at the value of a specific site. One is the potential revenues which can be generated at the site, and the second is the total development and operational cost which will be incurred.

On the revenue side, there is a wide range of possibilities. Under the Public Utility Regulatory Policy Act of 1978, utilities must agree to purchase power from small scale hydro producers at what is determined to be their avoided cost. Not all utilities will have the same avoided cost and thus, not all sites will have the same revenue potential. If a utility is a heavy user of oil, its avoided cost calculations will show a much higher buy-back rate under the PURPA regulations. On the other hand, utilities which generate most of their power with coal and nuclear plants will be required to offer less for the purchase of power.

Another factor which determines the amount to be paid by the utility is the extent to which they are over or under in terms of their capacity to generate power in relationship to the demand placed on their system. Utilities which have excess capacity over demand have no incentive to encourage small scale power producers. On the other hand, utilities which are capacity deficient will normally offer an incentive in the form of a capacity payment to small scale hydro producers.

Thus, sites comparable in all other respects will have different values depending on the buy back rates of the utilities involved. Some additional revenue, however, may be possible through wheeling to a utility with a higher buy back rate, or by selling the power to an on-site industrial user to whom the power may have a higher value.

The second major factor in determining the value of a site is the cost that is incurred to develop and operate it. Thus, some sites will be more attractive than others, based solely on cost considerations.

With respect to capital costs, sites with lower initial construction costs will have a higher value to a developer. A site with an existing powerhouse and penstock in place will be worth more than a site that would require installation of new facilities. Other items on this checklist would include the extent to which repairs would have to be made to the dam, the extent to which the tailrace or headrace would have to be dredged and repaired, and the cost of installing new transmission facilities to tie into the power grid or other end users.

Ultimately, the developer will compare the cost of construction to the overall cost per dollar of installed kilowatts. The two factors which determine the kilowatt capacity of a site are the stream flow and the head. Head is the distance the water falls and is probably the most critical variable in determining the value of a site. The cost per kilowatt falls significantly as the head increases. The reason for this is that less steel and other civil work is needed to generate a given number of kilowatts as the head increases. The formula for determining installed kilowatt capacity is as follows:

$$KW = \frac{\text{head} \times \text{flow (in cubic feet/second)} \times \text{efficiency}}{11.8}$$

As shown by the formula, any increase or decrease in head directly impacts on the number of kilowatts. A second major component is the stream flow as measured in cubic feet per second. A site with inadequate stream flow to produce sufficient kilowatts is also less attractive to a developer. When combined with the head, the stream flow must be sufficient to yield an installed capacity large enough to produce sufficient revenues to cover the fixed cost of development.

Each hydro site has certain fixed costs regardless of size. Such fixed costs are the Federal Energy Regulatory Commission and other government licensing process, the cost for preparing feasibility studies and design and engineering drawings, legal and financial placement costs, and utility buy back rate negotiation costs. The smaller the project, then the larger such fixed costs become in the total project. In addition, there are certain minimum equipment costs regardless of the size of the project. For example, even though a smaller site will require a smaller turbine and generator, the cost for certain electrical switch gear and control devices will be the same, regardless of size.

Each site must be looked at with respect to the overall cost of development. This means that if development of a site poses any special environmental or other related problems as part of the government approval process, then the overall value of the site to the developer goes down. An example of this would be the requirement to install fish ladders or to perform in-depth environmental impact studies prior to development. Likewise, sites which require special methods of construction in order to preserve nearby structures of historical or archeological significance would also have a reduced value to a developer.

The determination that a site would require any on-going operating costs of a special nature would detract from its value. An example of this would be excessive local property or income taxes that might be imposed on hydroelectric development. Another example would be the need for special insurance above that normally required for hydroelectric projects. Furthermore, regarding the size of the plant, the smaller the plant the higher will be the costs for operations and maintenance to gross revenues. Every site requires some monitoring whether it is 400 KW or 2400 KW. And yet the cost for monitoring is the same for both projects. Also, each site will have the same cost for billing and record keeping and other related overhead expenses.

Alternative Methods of Payment to Site Owners

There are two basic approaches to compensating the owner of a hydroelectric site. One approach is the outright purchase of the site and/or the rights to the site. A second approach involves the payment of royalty or lease payment to the owner with ownership of the site remaining with the site owner.

Under the first approach, the site owner may choose to sell the entire property or just the water rights and the property needed to produce power. Developers tend to avoid purchasing the full site because the total package often involves excess real estate in the form of land or buildings. Most developers don't want to be in the real estate business, so they prefer to limit their purchase to the water rights and only that property or easements required to generate power.

Under a lease or royalty arrangement, the owner is paid some percentage of the gross and/or net revenues. One variation on this involves guaranteeing a fixed minimum payment and a percent of gross revenues, whichever is larger. The risk to the developer is that the site in any given year may not generate enough revenues to cover all costs at the minimum royalty. Such a situation would require the developer to fund such expenses from sources other than the project. One way to protect against such a situation would be to have the cumulative gross revenues in past or future years credited toward these guaranteed minimums.

A more important consideration for site owners is the actual development plans proposed for their site. Owners should verify that the installed capacity and the total kilowatt hours proposed by a developer is the optimum that could be installed at the site. Unless the developer is required to install the optimum equipment, total gross revenues may not be as large as those which could have been obtained using some other configuration of equipment or civil work. In such a situation, it is the site owner who suffers economically.

Another third compensation approach would be to form a joint venture between the developer and the site owner. Normally, the owner would contribute the value of the site as the basis for an equity position in the overall project. This is an attractive method to developers since it provides the project with an equity base equal to the value of the site itself. It also has some attraction when structuring the financing for the project, especially where the site is marginal and cash flows in the early years must be used to cover debt service and other direct operating expenses.

In the event that a site owner has a need for the power, a fourth compensation approach might be tried. In this situation, the developer would sell the power to the site owner at some discount off the price the owner would have paid the local utility. Firms with dams on their property thus get a liability converted to an asset without having to commit any capital or bear any risk.

Negotiating a Fair Price

Because of the large initial capital investment required to develop a hydro project, it is essential that any price paid to an owner, either in the form of a royalty or as an absolute purchase, be compatible with the debt service needs of the project. As an example, consider the two projects as shown in Figure 1. Project A is clearly a more attractive site. It has a 40 foot head and costs $1750 per kilowatt to build, while Project B has only a 20 foot head and costs $2000 per kilowatt. Although Project A costs 3.5 million, it produces 8.76 GWH while Project B costs 2.0 million but generates only 4.38 GWH.

FIGURE 1

	PROJECT A	PROJECT B
Head	40'	20'
CFS	700	700
KWH per year	8.76 GWH	4.38 GWH
Rated capacity	2000 KW	1000 KW
Cost	$3.5 million	$2.0 million
Cost per KW	$1,750/KW	$2000/KW
Buy back rate	50 mills	50 mills
Gross revenues/year	$438,000	$219,000
Debt Service (30 years with 80% financing)	$373,500	$213,450
10% royalty	$43,800	$21,900
O + M @ 1% of project cost	$35,000	$20,000
Profit/(Loss)	($14,300)	($36,350)

For analysis purposes, it is assumed that both sites are financed with 80% debt at 13% interest (tax-free industrial development bonds) for 30 years. Project A has gross revenues of $438,000. If a royalty of 10% of gross revenues ($43,800) is piad to the owner, $394,200 remains to service the debt, and pay operating and maintenance costs. Debt service is $373,500 leaving $20,700 to pay taxes,

insurance, and maintenance which normally total about 1% of project costs, or $35,000. These funds thus may not be sufficient, and some renegotiation of the royalty may be needed. Clearly in Project B, there is not sufficient cash flow even to pay both debt service and operating and maintenance costs. For this project to be done, some delay in payment of a royalty and costs must occur until utility buy back rates rise high enough to provide the needed revenues.

Generally, only the most attractive projects can support a royalty payment of 10% or above. These sites will have low costs per installed KW and provide enough initial cash flow to pay all costs in addition to the royalty. Every site factor must be favorable. The site must have a high head, substantial flow, an existing powerhouse with a dam in good condition, minimum environmental problems, ease of electrical transmission, and be located in a utility service area heavily dependent on oil with high buy back rates. Most sites, however, don't meet all of these criteria and thus can't support payment of a royalty above 10%.

In fact, most developments may require some form of deferred or reduced royalty payments during the initial years until buy back rates rise sufficiently to cover costs. The only other alternative is to increase the equity contribution and reduce the debt level to bring yearly debt service requirements in line with yearly revenues. Any increase in the equity in a project, of course, lowers the return on investment and may not provide sufficient incentive to the developer to proceed.

There are several ways, however, to structure a marginal project to bring about its development. As already mentioned, the owner may defer royalty payments during the early years. In addition, developers and equipment suppliers may take back notes with deferred interest and principal payments on all or a portion of their share of the project costs. The expectation of course is that buy back rates will rise in future years.

The same analysis can be applied in situations where the site owner requires an upfront lump payment. It is relatively easy to calculate the value of a royalty payment in terms of an up front payment. The first step is to make an assumption on how much revenues will increase each year in the future, and also to select some period of time as the life of the project, perhaps 25 or 30 years. Each future year's after-tax royalty payment would then be discounted so as to convert these payments into present dollars. By adding these 25 years of discounted royalties, a present value for the site can be determined. The present value assigned to the site will depend on the inflation rate which is assumed for the increase in the buy back rate, and the rate at which future dollars are discounted back into current dollars.

Ultimately, the negotiation process by which the owner and developer reach an agreement on the value for a site (either up front payment, joint venture equity share, discount off utility rates or royalty/lease) will be the result of the competitive market forces at work. If a developer offers too little to the site owner, the the owner will either find another developer or do the job "in-house". If the owner asks too much, a developer will pursue other sites, rather than earn only a marginal rate of return for the effort and risks.

In attempting to establish the price for a site, the timing of the negotiations may pose problems. Neither the owner nor the developer has sufficient information on costs and, thus, what a site is actually worth prior to completing a detailed feasibility study. Some preliminary agreement, however, is necessary to protect the developer from an owner holding out for an unreasonably high royalty knowing that the developer has already spent a significant amount on the feasibility study. Conversely, the owner must be protected from the developer who offers an unreasonably low royalty once the site is tied up with a Federal Energy Regulatory Commission permit, knowing that the owner can deal with no other developers until the permit period runs out.

One solution is a preliminary agreement made prior to the feasibility study and prior to the end of the FERC notice period which sets a minimum royalty payment of 5% and a maximum royalty payment of 10%. Both parties would then be free to negotiate a final agreement on a royalty payment between these two limits once the data on the site were available from the feasibility study. The owner would be freed from having to work with the developer if the royalty offered were under 5%. Likewise, the developer would be able to proceed with the project by paying no more than the maximum 10% specified in the agreement. Such an agreement thus protects both the owner and the developer and sets reasonable limits on what either can demand in the negotiation process.

Public Versus Private Development

Over the years numerous dam sites have reverted back to municipal ownership for any number of reasons. Many municipalities are not faced with the decision of whether to pursue the development of these sites. The purpose of this section is to provide some insights into the use of private initiative and dollars as an alternative to public sector development.

In most cases, the public development of a hydroelectric site will require some use of municipal employees to manage and participate in the development plans for the site. Generally, the development state will run for a minimum of one year, and possibly as long as two or three before the project is actually built. Such commitments of staff time to a hydroelectric project may prove difficult for municipalities now struggling to meet other operating budget constraints. In addition, the commitment to fund a municipal project requires the use of some of the municipality's borrowing capacity. Such a commitment may not be feasible or less attractive than if the funds were used for other more critically needed projects.

In addition, private developers have certain tax advantages available to them which will provide more encouragement for development of a site than if public sector financing were used. While it is true that municipalities may borrow funds at a tax-free rate, such financing does not offset the advantages that can be had by a private developer. Under the current tax laws, a private developer may claim a 10% investment tax credit as well as an additional 11% energy tax credit for a total of 21% of the major portions of a small scale hydroelectric project. In addition, small scale hydroelectric projects are eligible for accelerated depreciation and, on average, this means that about

50% of the project can be written off during the first three years of the project's life. The attractiveness to private investors is therefore very substantial. In addition, the interest paid by private developers is tax deductible, thus bringing this cost below the tax-free municipal rate.

One alternative for a municipality with limited borrowing capacity would be to turn the site over to a private developer. A typical financial structure for a private developer would be to create a limited partnership. In such an arrangement, individual investors in high income brackets would contribute approximately 30% of the project in cash equity and sign recourse notes for the remaining 70%. These notes and the project revenues would be borrowed against using a financial institution to provide the long term debt. The investor benefits by receiving an equivalent amount of tax saving benefits during the first year to offset the actual cash equity investment. Future tax benefits are also passed through to the investor. Eventually, when the project is refinanced or sold, the limited partners receive the benefits as capital gains and not ordinary income. Such arrangements may allow a project to be developed which would not be financable through public sector financing. Municipalities should explore this route prior to abandoning plans for development.

The benefit to the municipality is a relatively risk-free asset which will generate a positive cash flow in the form of a royalty payment or lease payment. In addition, the municipality will have none of the financial risk and will not have to spend any funds from the operating budget for on-going maintenance and management of the project.

Summary

While there is no clear formula that can be applied to every hydroelectric site, the points outlined above should provide a framework for analysis when attempting to reach a fair value placed on a potential hydroelectric site. Developers obviously must attempt to structure their payments to meet the needs of site owners, and site owners must recognize that there are limits to the amount of payment which they can demand.

NON-FEDERAL HYDRO DEVELOPMENT AT CORPS PROJECT

Gary Petrewski and Salvatore Bucolo
as delivered in Harrisburg, Pennsylvania, May 12, 1981

(Title Slide) Good afternoon ladies and gentlemen. I personally welcome this opportunity to make a presentation on the topic of hydropower development in the region, and more specifically, development at Corps of Engineers' projects.

There are three primary messages which I'd like to convey. The first which I'd like to state simply is the the Corps of Engineers both supports and encourages hydropower development of its projects by non-federal interests. The second and third messages which I will be discussing in more detail are that the Corps has the responsibility to insure that its projects are operated in the public interest and because of this, non-federal development at our projects is subject to certain requirements.

(Hydropower) I'd like to begin by briefly discussing the Corps general functions and our historical and recent role in hydropower. I'd then, like to focus in on the Pennsylvania, Maryland, Delaware area, discuss our projects and the current interest in development at these sites. I'd also like to review our requirements for non-federal development.

As general background, since 1824 the Corps has been actively involved in the development and management of the country's water resources. We've executed major national programs for navigation, flood control, water supply, hydroelectric power, recreation and water conservation.

(Historic) Historically, the primary function of the Corps has been in the area of navigation. Throughout the inland waterway system the Corps has constructed numerous lock and dam projects. (Allegheny L/D) A number of these projects already incorporate hydropower while most others are sites being given primary consideration today.

(Bonneville Project) In the face of today's energy situation we look back in time to over 40 years ago when the Corps first started a comprehensive hydroelectric program which was marked by the design and construction of a 518 megawatt plant at the Bonneville Lock and Dam on the Columbia River in Oregon. Since that time, particularly since the end of World War II, the Corps has expanded to the nation's largest builder and operator of hydroelectric facilities. (Corps Hydro Projects) We currently operate 67 projects with a total installed capacity of 18,300 megawatts, which represents about 26 percent of the total developed hydropower capacity in the nation and about 3 percent of the nation's total electrical energy capacity. About two-thirds of this capacity, however, is located in the Pacific Northwest where historically it has been the most economic way to meet energy requirements.

(Montgomery L/D) In this region of the country, hydropower development has rarely proved economical due to the abundance and low cost of other fuel sources such as coal and oil. Today, as we are all aware, that situation has changed. As a result the Corps and other interests are taking a close look at adding power to a number of Corps projects in the region.

(Prompton) What we find in looking at our existing projects is that they serve a valuable purpose. Whether it be for flood control, navigation, water supply or other purposes, existing reservoirs in the region are committed to serve the public. Their use for these (Blue Marsh) purposes has been carefully planned. Functional commitments to other agencies and the public have been established. Their function cannot be compromised, but where the possibility exists their functions can certainly be expanded to include hydroelectric generation.

(Local Corps Projects) Taking a closer look at the projects in this region, as shown on the slide, the Corps currently operated 44 reservoir and lock and dam projects in the states of Pennsylvania and Maryland which are of the type suitable for hydropower development. Only a few of these projects, primarily our dry or near dry flood control reservoirs, do not appear viable for some level of hydroelectric generation. The remaining reservoirs, exclusive of our navigation locks, typically serve multipurpose functions such as flood control, water supply and recreation.

(NHS Study) The potential of our projects has certainly not gone unnoticed. Four years ago the National Hydropower Study was initiated by the Corps. The purpose of the study was to conduct a nationwide assessment of our hydroelectric resources. This included not only Corps and federal projects but non-federal projects as well. Today, as we approach the completion of that study, 37 of the 44 projects in this region have been included in our final plans. Combined, these projects have an estimated generating capacity of 444.2 megawatts of conventional capacity which remains undeveloped. Out of this total, 131.4 MW have been identified at locks along the Allegheny River, 68.2 MW at locks along the Monongahela and 98 MW at locks on the Ohio River within the state of Pennsylvania. The remainder of the capacity is at our reservoir projects primarily within the state of Pennsylvania.

(Studies/ Interest) Your interest in developing Corps projects is, however, what brings me here today. To give you a feel of current study activity, let me give you a few more numbers. Preliminary permit applications have been submitted to the Federal Energy Regulatory Commission at 37 of our projects. A total of 94 applications for preliminary permits have been submitted; 14 to date have been issued. There is also one license application pending. In contrast to non-federal interest the Corps is currently conducting studies at 13 sites. In addition, we have congressional authority to undertake studies at 7 other sites, and have an outstanding authority which was delegated by Congress to the Chief of Engineers, to undertake preliminary studies at the remainder of our projects. Competition to develop sites is evident.

(Federal vs Non-Federal)

This competition has raised several problems and questions. The first problem we see is duplication of effort. It seems obvious that a decision must be made as to whether the Corps should conduct a study of its own project or, in accordance with our policy to support non-federal development, we should back off and allow others to proceed with their work. Unfortunately this question can't be answered in general terms. Each project offers a different range of generation potential. Determining the scale of hydropower development at any one project, in order to best serve the public interest, oftentimes requires a careful examination of project purposes, and extensive study to make best use of available resources.

What must be realized is that the function of Corps projects is not a constant. In the interest of comprehensive river basin management, federal projects play a variable role, and are subject to change as local needs change. For example, several Corps

(F.E. Walter)

projects in the region, such as the Francis E. Walter Project, shown on the slide, are currently being examined to develop additional water supply storage. Until these studies are completed by the Corps, independent studies of hydropower by non-federal developers may be nonproductive.

In other cases, hydropower development options are straightforward

(Conemaugh Lake)

and non-federal development appears appropriate primarily due to the fact that the development could proceed more quickly than if undertaken by the Corps.

Although the Corps is currently initiating actions to accelerate hydropower development at its dams, including fast-track planning, design and construction capability, until new legislation is enacted, it will be difficult to move expeditiously through the normal lengthy authorization route.

(Kinzua Dam)

With the knowledge that we must streamline our procedures in order to get hydropower on-line quickly we stand in support of non-federal development at our projects. To date there are 25 Corps projects throughout the country at which non-federal developers are producing power. One example in this region is the Seneca Power Plant, shown on the slide, which is located on the Corps' Kinzua Dam in Northwestern Pennsylvania. Over the next few

(Coordination Slide)

years we expect this number to increase substantially and are willing to cooperate to see that it's done. We have the congressional authority as a result of Title III of the Intergovernmental Cooperation Act of 1968 to provide technical assistance on a reimbursable basis to public entities who have received a preliminary permit or license from FERC. The assistance can be an entire feasibility study. This authority has been put to use on the North Hartland Dam in Vermont where the Vermont Electric Cooperative has contracted with the Corps to conduct a portion of their feasibility study. The authority, itself, offers the opportunity for close coordination between the Corps and non-federal developers.

(Requirements) Coordination with Corps offices is, of course, an important consideration in your studies. That's why in the next few minutes I'd like to give you a rundown of our requirements for development at our sites.

Compatible with the Federal Power Act, the first requirement is that the total power potential of our sites must be considered. This allows for development in stages but disallows under-development to meet an arbitrary energy requirement or objective. Projects should at all times be considered as part of a comprehensive basin system and should be developed to provide the most benefit to that system. As an example, it would be inappropriate for a developer to size the project to meet his own energy needs if the potential exists to develop additional power which could be used in the region.

The second requirement is that hydro must be compatible with the authorized purposes of a project. Verification of compatibility may require modeling efforts at the applicant's expense. For example, if pondage is required for the operation of the hydropower project, we must insure that this does not impact our operations for water supply, flood control, or navigation.

The design, construction and operation of all power facilities that will be an integral part of the dam or that would affect the structural integrity of the federal dam, including construction procedures and sequence, must be approved by the Corps. Design and construction must be compatible with Corps specifications in order to get approval. The approval process is a cost to be borne by the developer.

In the interest of multiple-purpose water management, the Corps may require a signed memorandum of understanding between a licensee and the Corps specifying the operational procedure power rule curves consistent with overall project management objectives.

The licensee must reimburse the Federal government for the lands and facilities, and for an appropriate part of the coexisting Federal project by which the head created at the Federal project makes the installation of power possible. Reimbursement to the Federal government will also be required for any additional constructions costs incurred by the government as a result of installation of the power facilities. Stated more simply, costs will be assessed the developer to insure the public investment in the project.

Power must be furnished free of costs to the United States for operating and maintenance of the project facilities in the vicinity of the project at voltage and frequency required by facilities, whether such facilities are constructed by the licensee or by the United States.

The prospective licensee shall furnish, operate and maintain adequate lights, signals and protective warning devices in conjunction with pondage operation, if it exists, to provide safe navigation and for the safety of persons using the public recreational facilities at the Federal project.

Finally, in compliance with Section 404 of the clean water act, a Department of the Army permit is required for any discharge of dredged or fill material (into the waters of the United States), including activities associated with hydropower development. The permit will require a full public interest review by the Corps of an applicant's proposal.

Of these requirements the one of most concern is the requirement that charges be made for use of the dam and facilities. Under the Federal Power Act the Federal Energy Regulatory Commission has the responsibility to fix charges to compensate the government for use of the dam as well as other lands and property. Generally the Corps, in reviewing an application for license, will recommend the level of charges to be assessed. FERC may or may not concur. FERC has used a "sharing-of-the-net-benefits" approach for fixing these charges. Using this approach, the charge would amount to one-half of the net profits produced by the project. This assures that the government and the developer share equally in the benefits generated by the installation of power. FERC, in the interest of promoting development, is currently formulating a revised methodology for estimating charges. In the next few months these procedures should be finalized and made available for estimates by developers.

NON-FEDERAL DEVELOPMENT OF HYDROPOWER OF U.S. ARMY CORPS OF ENGINEERS PROJECTS

Robert L. Nordstrom
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Mr. Nordstrom is a graduate of the Virginia Polytechnic Institute (BS - Civil Engineering). He has served as a Reserve Officer in the Navy Civil Engineer Corps for four years and is a Registered Professional Engineer in the state of Florida.

As chief of the Water Management Division at Fort Norfolk, his main concern is the planning and development of single and multi-purpose water resource projects. His career has projected him into the hydraulic design of dams, channels and levees. Planning concerns include investigations for development of hydroelectric power at proposed sites as well as operation studies at existing sites. Mr. Nordstrom is exceptionally well qualified by this experience to discuss hydropower at both Federal and private sites.

The Corps of Engineers, as the nation's primary agency for water resources development and management, plays a significant role in meeting the nation's power needs by building and operating hydropower plants in connection with its large multiple-purpose dams. Although many public and private groups and two other Federal agencies, the Water and Power Resources Service and the Tennessee Valley Authority, have also developed water power resources, the Corps of Engineers is the nation's largest builder and operator of hydroelectric facilities. As of April 1979, it operated 67 projects housing 317 turbine-generating units having a total installed capacity of 18,300 megawatts with an additional 900 megawatts under construction at five other projects. The hydroelectric capacity of the Corps comprises about one-fourth of the nation's hydroelectric capacity. About two-thirds of this capacity is in the Pacific Northwest, where the Corps provides nearly half of that region's requirements. In the northeast, the Corps operates no hydroelectric generating facilities. Of the rivers which flow into the Atlantic Ocean, only the Roanoke River Basin and those basins further south contain Corps projects with hydropower.

The Corps of Engineers has no general authority for the development of hydroelectric power. Hydroelectric facilities at Corps dams have been built indirectly as a result of achieving other goals. The primary mission of the Corps in water resources development has been in the areas of flood control and navigation with other purposes included in projects to ensure optimum development of the resource. Hydroelectric power has therefore been considered a secondary benefit of our water resources projects.

Although the Corps builds and operates generating facilities at many of its dams, it doesn't sell the power. Under Federal law, power generated at Corps projects is marketed through marketing agencies within the Department of Energy.

Because the Corps has constructed and operated a number of projects which include power generating units, we have had the opportunity to become familiar with some of the problems encountered when generating units are added to a project. At this time I would like to discuss in fairly general terms some of the problems that have been experienced.

While hydropower generation is a non-consumptive water use, it may compete with other project uses for the water in a reservoir. To achieve optimum use of streamflow for power generation, seasonal variations in rainfall normally require an operating rule curve which reaches its lowest elevation during the fall or winter. This ensures that storage space will be available to capture high spring runoff. The stored water can then be used to supplement low streamflows during the summer months. Since most of our projects also include recreation, a conflict develops with the need to maintain a stable pool during the summer months if recreational use is to be optimized. Thus, trade-offs must be made between power and recreation to achieve maximum beneficial use of the project.

We have also found that the inclusion of power generating units at a project may result in certain social and environmental problems. Most problems associated with the operation of hydropower generating units can be traced to a natural phenomenon that affects all lakes or to what we have come to accept as a normal life style in our society.

When a dam is constructed across a river, we change that reach of the river from a free-flowing stream to a lake. Because water densities are sensitive to changes in temperature, lakes of any appreciable depth in temperate climates are likely to exhibit thermal stratification during the summer months. While this may result in beneficial impacts, it may also lead to problems. Water trapped in the bottom of these lakes has no opportunity to absorb oxygen from the atmosphere. The oxygen-consuming activities at the bottom of the lake continue, and dissolved oxygen levels in these waters may approach zero.

The release of this water can have adverse effects on the temperature and dissolved oxygen content of the water downstream. At projects without hydropower generating facilities, the adverse impacts of releasing oxygen-deficient water have been avoided in a number of ways:

A. Sometimes water may be released from high-level spillways where the waters are likely to be rich in oxygen.

B. Intake towers may be designed to permit withdrawal of water from selected levels in the reservoirs to achieve a desired quality of release, or

C. Water may be withdrawn from the lower levels of the reservoir and released in a manner that will ensure a high degree of oxygen absorption. The Corps has found that especially designed low-flow systems which release high velocity jets into larger outlet tunnels can achieve a high degree of success and that the turbulence in stilling basins may contribute significant quantities of dissolved oxygen.

When releases are made through hydraulic turbines, dealing with this problem becomes more difficult. To obtain maximum energy from the water released, penstocks should be as short as possible to minimize head losses and water will be released with a minimum of turbulence if maximum energy conversion is achieved. The probability of releasing oxygen-deficient water is therefore increased. Efforts to overcome this problem in both the public and private sectors include:

A. Locating intakes higher in the reservoir.

B. At existing projects, constructing a weir upstream of the intakes.

C. Installing vacuum breakers on turbines which are operated at low loading, and

D. Designing the tailrace to increase turbulence so that the reaeration rate is increased.

If we are successful in overcoming the problems imposed by nature, we may find that we are faced with another set of problems created by what we consider a normal life style.

If we examine the daily load curve of a typical utility, we find that it reflects the pattern of our daily activities. Between midnight and the daylight hours, while most of us are asleep, the electrical load is relatively small. As we arise and begin our daily activities, the load increases -- reaching peaks during the hours of our greatest production. To accommodate this varying load, utilities typically use their most efficient thermal facilities in the base of load where they will get maximum use, operate less efficiency thermal units in a band above this base, and use hydropower to supply the peaks. Maximum support of this electrical load by hydro generating units would, therefore, be obtained by making all releases during this period of peak load. However, this would result in releases being made only a few hours per day and would tend to nullify the benefits to low-flow augmentation at projects where storage has been included for that purpose. It could also create problems for downstream users who may be depending upon a more uniform rate of flow for their activities.

The most common methods of dealing with this problem is to construct a regulating dam downstream from the powerhouse to ensure a more uniform flow or to establish minimum releases during periods when generation is not required.

I realize that many of the hydropower generating units being planned today are not peaking units and many of these problems may not exist. I have presented these problems so that any of you who may be considering the installation of power generating units at a Corps dam will have a better understanding of the concerns that might arise during the planning and design of these facilities.

At this time, I would like to present the general requirements for construction of hydroelectric power facilities, under Federal Energy Regulatory Commission license, at Corps of Engineers lakes, and locks and dam projects:

A. Hydroelectric power development must be compatible with authorized purposes of the Federal project. Verification of compatibility may require physical and/or mathematical modeling, the cost of which should be borne by the applicant.

B. Design, construction and operation of all power facilities that will be an integral part of the dam or that would affect the structural integrity of the Federal dam, including construction procedures and sequence, must be approved by the Corps.

C. In the interest of multiple-purpose water management, the Corps may require a signed memorandum of understanding between the prospective licensee and the Corps, specifying the operational procedures and power rule curves consistent with overall project management objectives.

D. Prospective licensee must reimburse the Federal Government for the use of lands and facilities and for an appropriate part of the cost of existing Federal project by which the head created at the Federal project makes the installation of power possible. Reimbursement to the Federal Government will also be required for any additional construction costs incurred by the Government as a result of installation of the power facilities.

E. Prospective licensee must furnish power free of costs to the United States for operation and maintenance of the project facilities in the vicinity of the project at voltage and frequency required by such facilities, whether such facilities are constructed by the licensee or by the United States.

F. The prospective licensee shall furnish, operate and maintain adequate lights, signals and protective warning devices in conjunction with the pondage operation to provide for safe navigation and for the safety of persons using the public recreational facilities at the Federal project.

G. In compliance with Section 404 of the Clean Water Act, a Department of the Army permit is required for any discharge of dredged or fill material (into the waters of the United States), including activities associated with hydropower development. Such permit will require a full public interest review of applicant's proposal by the Corps. Early coordination in this regard with appropriate Corps of Engineers district offices is essential.

The Corps encourages hydropower development at its dams, whether by Federal or non-Federal interests. Directives from the Office of the Chief of Engineers to field offices have been clear in support of non-Federal hydropower development at Corps dams, provided that such development is based on sound engineering design, has no significant adverse environmental effects, fully uses site capability and does not significantly interfere with other Congressional authorized project purposes. Currently, there are 25 Federal Energy Regulatory Commission licensed non-Federal hydropower projects at Corps dams, most of which are in operation.

The Federal Energy Regulatory Commission is responsible under the Federal Power Act for licensing of non-Federal hydropower development at Corps dams. Corps involvement in such development is through review and approval of license and permit applications in which the proposed design, construction, and operation impact our projects.

MODULAR HYDRO DAM APPROACH TO THE
ECONOMIC DEVELOPMENT OF ULTRA LOW-HEAD HYDROPOWER

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Mr. Broome received his BA and MA degrees in Mechanical Sciences from Cambridge University. After practicing as a Chartered Civil Engineer in London, he spent twenty years in California on the structural design and project management of various industrial projects including the development of innovative facility concepts for solid fuel rocket manufacturing and test, a shipbuilding facility for series production of military supply vessels, and the development of a concrete box type of industrialized housing. After managing the successful field demonstration of the housing system, Mr. Broome moved to Gilbert Associates in Reading, Pennsylvania, where he is now responsible for management of major Civil Engineering projects and the development of the firm's capability for small-scale hydropower design.

The solution to developing economical ultra low-head (10 ft. - 6 ft., 3 m - 2 m) hydropower lies in being able to reduce equipment and construction costs at new dams to less than $4,000/KW, while maintaining an operating efficiency of 80% or more. There are a number of existing ultra low-head dam sites in the contiguous 48 states that can be developed in a marginally economical manner at the present time using conventional technology. As these existing sites become developed, however, the value of new sites will grow.

The purpose of this investigation is to explore the potential for developing economical new ultra low-head sites using an innovative concept known as the Modular Hydro Dam (MHD). This concept, as shown on Figure 1, combines the benefits of shop fabrication and installation of equipment in truck transportable, waterproof power modules, with prefabricated gate sections that can be located between the power modules. Lateral support to withstand the static head pressure is provided by an upstream tension cable system anchored at each bank. Foundation design for vertical support varies with subsurface conditions; but wherever practical, construction will be carried out in the wet without diversions or cofferdams. Maintenance access to the modules and gates can be provided by a carriage that travels on runway beams spanning between the modules or from a barge.

Over 1,700 potential MHD sites were identified within the contiguous 48 states along rivers that have relatively flat gradients and steep banks. The key factor in site selection was the potential for maintenance of the reservoirs at elevations below that of the average annual flood for that particular reach of a river. Apart from the presence of the power modules which are similar in size and spacing to the piers of a bridge, no restriction will be caused to flood waters when the full width gates are automatically opened during flows that exceed the capacity of the turbines.

The Department of Energy, through its Idaho Operations Office, has funded a cooperative study with the author's firm, Gilbert Associates, Inc., of Reading, Pennsylvania, to study the potential for development of the MHD concept. This presentation describes the preliminary results of the study which is presently nearing completion.

The purpose of the study during this first phase of the project was to define the MHD concept to the point where capital and operating costs could be estimated; to determine the potential applicability of the concept within the contiguous 48 states; and to estimate the economic, environmental, and institutional feasibility of utilizing the concept. Should the results of the study be considered sufficiently favorable, it is proposed to carry out a component development and testing program during the second phase of the project for the innovative aspects of the design, followed by a third phase prototype demonstration in order to determine actual operational performance characteristics at full scale.

The following range of river characteristics were established at the beginning of the study:

	Width - Ft.	Mean Annual Flow - cfs
Case 1	500	2,000
Case 2	1,000	10,000
Case 3	2,000	30,000

Figure 2 shows a general arrangement plan and section of the preferred design of an axial-flow type of turbine in a fabricated steel module using an Allis-Chalmers mini-turbine with a 72 inch runner rated at 300 KW under 10 ft. nominal head. The generator is mounted above the turbine in a watertight compartment. The use of a belt drive permits speed increase without the cost or losses of a mechanical gear drive. A vertical intake gate is contained within the module as also are the electrical control system and switchgear. A trash rack is installed across the intake opening.

The size and weight of the power module permits it to be fully assembled and checked out in the manufacturer's shop, except for the draft tube extension which is shipped separately. The module can then be shipped by truck to the site. Once in place, concrete ballast will be added, as necessary, to prevent flotation.

An alternative power module concept was developed as shown in Figure 3. This concept was designed to use a Cross-Flow type of turbine such as the Ossberger firm in Germany has developed. Design and performance information and cost estimates on the Ossberger turbine were supplied by F. W. E. Stapenhorst, Inc., of Quebec, Canada, under sub-contract to Gilbert.

This alternative is rated at 176 KW at 10 ft. nominal head and is also transportable by truck. From an operational standpoint, it is considered equivalent to the axial-flow turbine module, although its lower output and greater cost makes it less attractive from an economic standpoint.

Horizontal movement of either type of module in the downstream direction is prevented by a cable system installed upstream in the river bottom which may be pretensioned by a force equal and opposite to the maximum hydrostatic forces expected under normal operating conditions. The frictional resistance between the module and its foundation will normally exceed this force. However, during flood conditions or under ice loading when the horizontal forces in a downstream direction may exceed such frictional resistance, the cable system will be designed to take care of the extra forces that exceed the frictional resistance even if a minor displacement of the module on its foundation should result.

The type of foundation will, of course, depend on the river bottom configuration and materials. In order to develop typical foundation designs, three classifications of river bottom material were established as follows:

Bedrock	-	exposed, weathered, and fissured.
Strong alluvium	-	sand and gravel
Weak alluvium	-	mud

In order to provide a level surface strong enough to support the modules and gates without significant settlement, and impervious enough to prevent underflow and piping of fines that could result in subsidence, varying degrees of foundation improvement are required as follows:

Bedrock	-	removal of weathered rock and higher portions and filling of lower portions and fissures in order to achieve a level, sound foundation.
Strong alluvium	-	levelling and grouting as needed to provide a level, impervious foundation.
Weak alluvium	-	removal of unsuitable material and replacement with sufficient suitable material followed by levelling and grouting as for strong alluvium.

The relationship of head difference (10 ft.) and length of flow path (50 ft.) is such that piping is not expected to be a problem at most sites. Additional grouting may be required at sites having unusually permeable subsurface conditions.

Construction of the foregoing types of foundation will require different methods depending on the amount and type of work involved, the degree and length of exposure to flood conditions, and the need for diversion of low flows.

Under the most favorable conditions, it is expected that the foundation and module/gate installation work can be carried out in the wet without the use of temporary cofferdams or stream diversion works. Increasing degrees of difficulty and exposure will require progressively more extensive temporary works and increased construction cost and longer time schedules.

Various kinds of movable gates were studied that ranged all the way from fabric curtains through inflatable dams, to conventional Bascule type gates as manufactured by Allis-Chalmers. The economic spacing of axial-flow type modules is such that the length of gates should be about 70 ft., which is within the limits of truck transportation with a special permit in most states. The criteria for selection of the preferred type of gate are as follows and as shown on Figure 4:

- Reliability of operation under all conditions of flow and weather by fully automatic means.
- Economy of total life-cycle cost for the life of the facility (50 years).
- Controllability over the range of operational flow conditions.
- Ability to pass ice and debris.
- Survivability under extreme flood conditions.
- Portability as a completely checked-out and pre-assembled unit ready to be installed.
- Demonstrated performance under all extreme and normal operating conditions.

The Bascule gate is the preferred concept in all respects, except reliability and economy. A new concept known as the "Butterfly" gate was developed during the course of the study and is considered to be potentially more reliable and economical. However, since it is as yet unproven, the concept must be developed and tested before it can be utilized. This concept is shown on Figure 5.

It consists of a single fabricated steel structure that is shaped to present minimum flow resistance when in the open, horizontal position. It is pivoted at either end in trunnions supported by the power modules. The trunnions are located at approximately one-third of the height of the gate in its closed or upright position. The exact pivot point is determined by the depth of overflow desired before the gate will open. The basic principle of the design is that any depth of headwater on the upstream side has a center of pressure at two-thirds of its depth. Similarly, the center of pressure of the tailwater on the downstream side is also at two-thirds of its depth. As the depth of headwater increases with a developing flood, the center of headwater pressure rises until there is a positive moment exerted about the axis of the pivot sufficient to overcome friction and to cause the gate to rotate to the horizontal attitude.

The gate is ballasted at its lower end such that it is almost balanced when translated to the horizontal attitude. With the proper streamlined shape, it will remain virtually horizontal until the flood has passed, at which time the slightly bottom heavy ballast bias will bring the gate back to the vertical attitude and permit rising headwater pressure to re-seal the gate against a raised portion of the foundation.

In order to demonstrate the feasibility of this gate concept, some theoretical studies and model tests are needed. Such work is beyond the scope of the first phase of this project and must be deferred until Phase 2.

The cost of representative prototype MHD installations in 1981 dollars has been estimated to range from $4,500/KW using a fabric curtain gate constructed in the wet, to $7,500/KW with hydraulically operated steel pelican gates. On a repetitive basis following the normal learning curve which can result in as much as a 50% savings in shop labor hours; and with the development of improved design and construction methods in commercial applications, it seems reasonable to expect that savings of between 10% and 20% might be realized when the MHD concept has been reduced to practice. The cost range at a 15% reduction would then be $3,825 to $6,375. The prototype cost estimate breakdown is shown on Figure 6, together with major qualifications.

Assuming a capital cost of $4,000/KW for commercial installations in 1981 dollars, a public agency able to obtain bond financing at 12% interest and inflation assumed at 9% a year would have fixed costs, including taxes and insurance, that would amount to $640 per year per kilowatt. Variable costs for operating and maintenance are estimated to be $50 per year per kilowatt.

With a capacity factor of 0.4, average annual energy generation would be 4,600,000 KWH for a 500 ft. wide installation developing 1300 KW. In order to break even, energy must have a value of 10¢/KWH for the public agency or up to 16¢/KWH for privately-owned organizations. Of course, lower interest rates would result in reduced break-even values.

The time frame within which the MHD concept might be reduced to practice is dependent on the degree of urgency with which it is developed. The shortest period would involve the Phase 2 Testing Program being carried out by mid-1982, followed by a full-scale prototype demonstration during the subsequent 3-1/2 years, which would mean the earliest start for the first commercial project would be in early 1986 to be on-line in 1990.

By 1990, most, if not all, available existing dam sites for small hydro in this country will probably have been utilized. Overseas, this point has already been reached in many countries since there has been little previous development of water power on a small scale, and not many dams built for flood control or navigation purposes. The few water supply dams that have hydro potential are likely to be developed in the next several years.

It is therefore concluded that there is a justifiable need for development of the MHD concept as being an economic as well as an environmentally acceptable solution to electric power generation needs both in this country and as an export market for overseas. The savings in fossil fuel in this country, if all 1,700 potential sites were developed at an average capacity of 1,300 KW, would exceed 136,000,000 barrels of oil or 40,000,000 tons of coal per year.

Overseas the degree of prefabrication and the portability of components will permit site installation to be carried out almost entirely by local labor with only minimal involvement of supervisory personnel from the manufacturer. Since the MHD concept has been defined with funds from a U.S. Government agency, the results are in the public domain and available for anyone to utilize all or part of the concept if they wish to proceed with development using private sources of funding.

If the potential that we presently see in this concept can all be realized, it may well be that small is both beautiful and practical.

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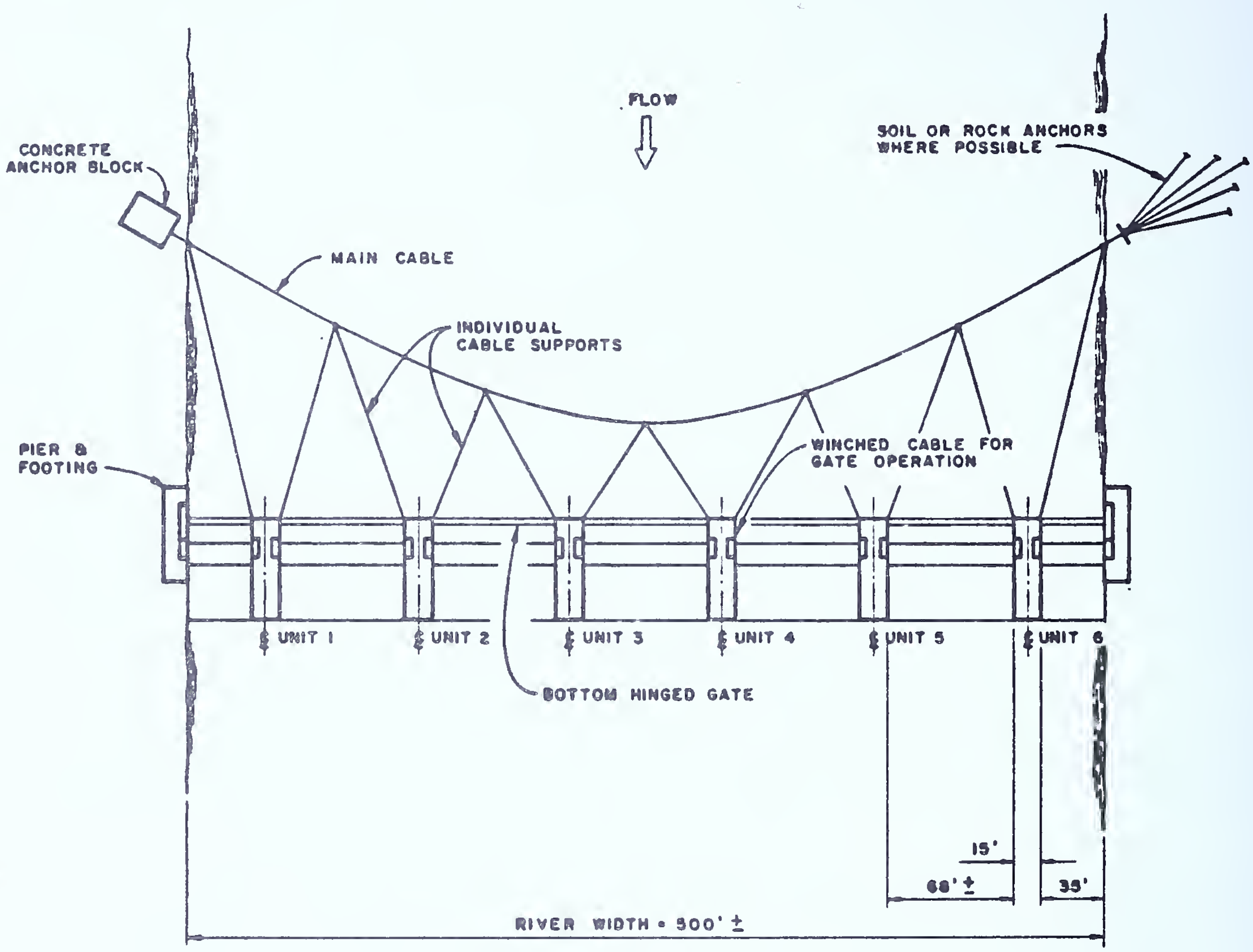
FIGURES



PLAN

FIGURE 1
MODULAR HYDRODAM
GENERAL ARRANGEMENT
500' WIDE RIVER

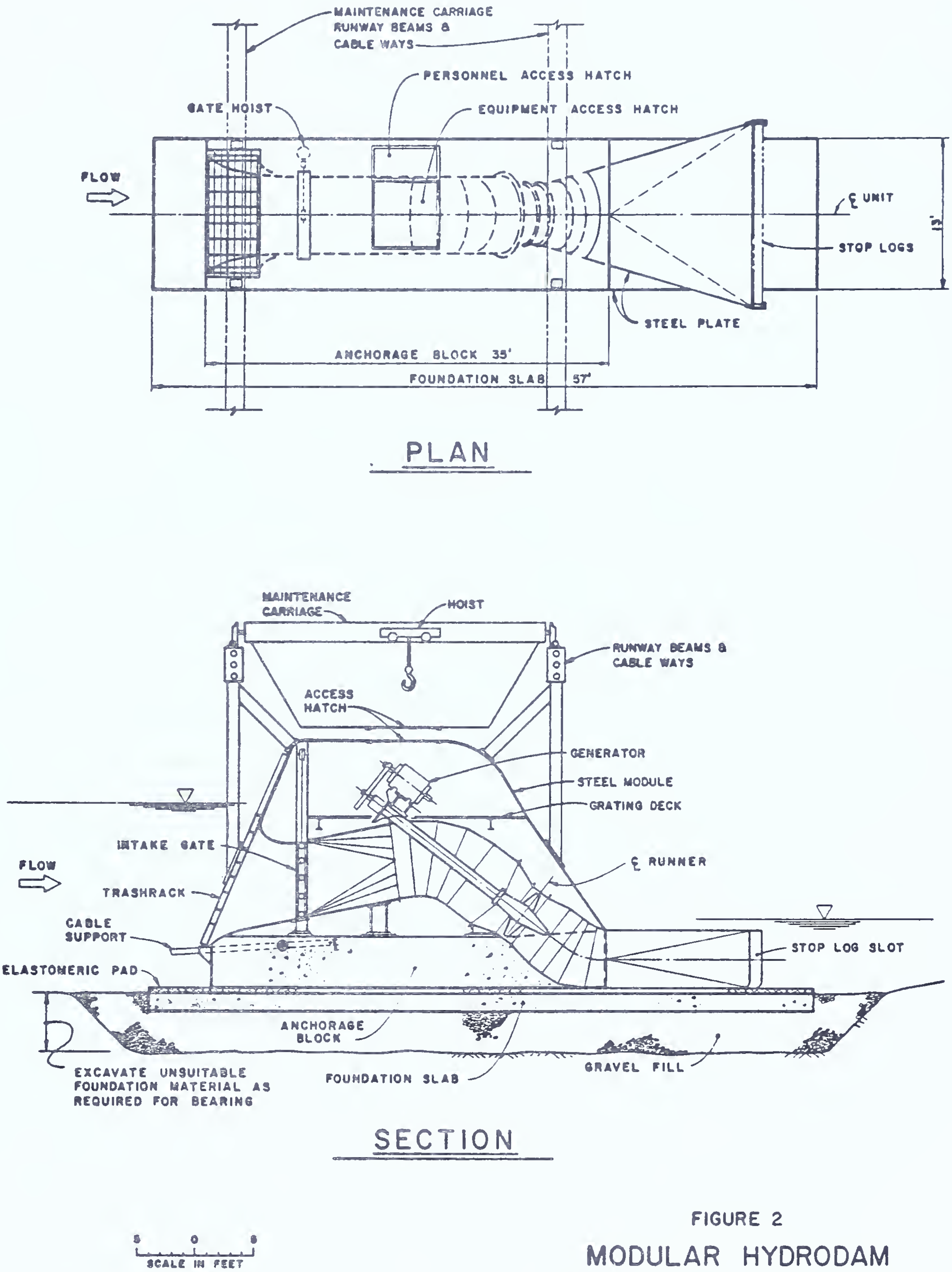


FIGURE 2
MODULAR HYDRODAM
AXIAL FLOW POWER MODULE

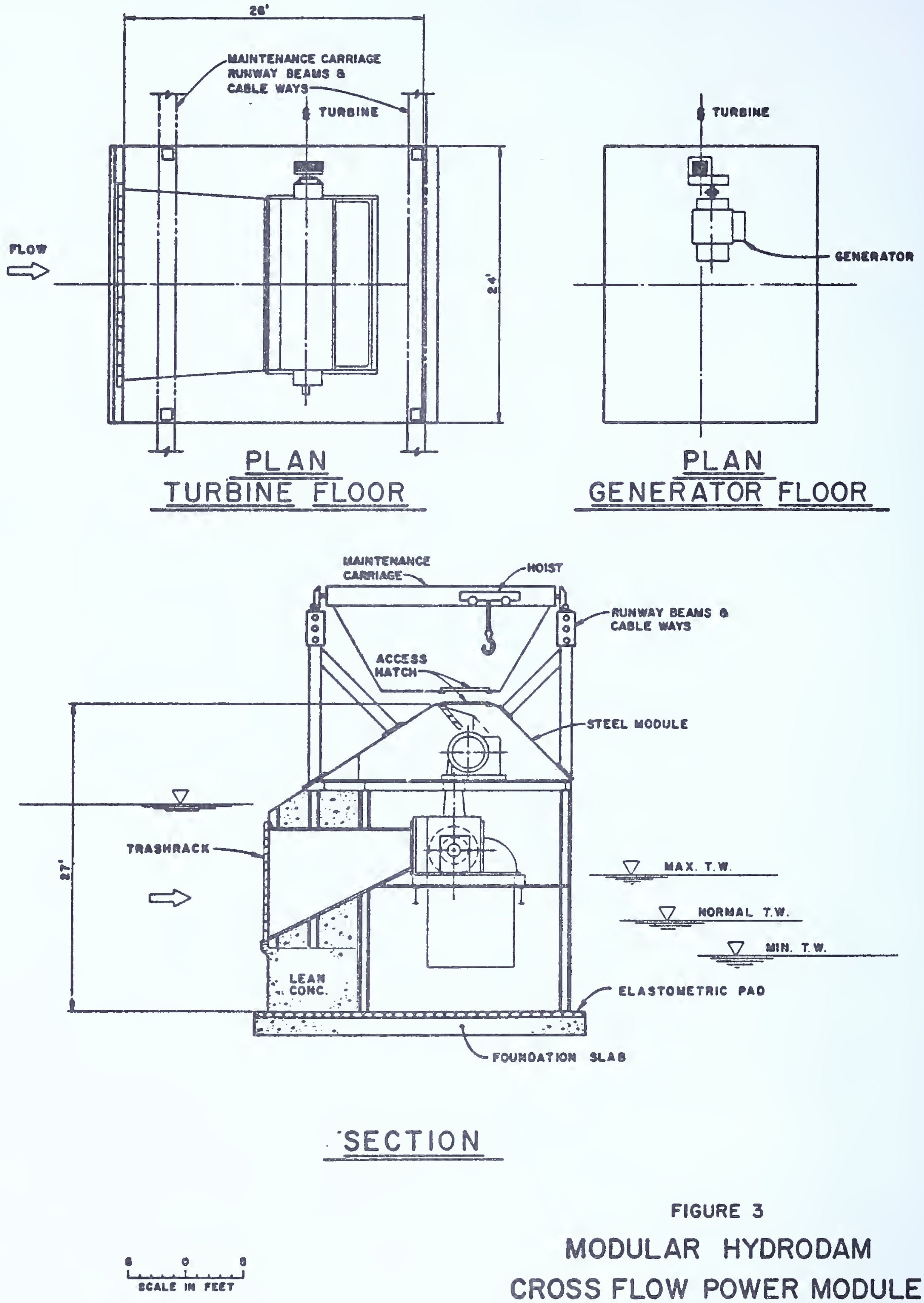


FIGURE 3

MODULAR HYDRODAM
CROSS FLOW POWER MODULE

CRITERIA FOR SELECTION OF CONTROL GATES FOR MODULAR HYDRO DAM

- RELIABILITY OF OPERATION UNDER ALL CONDITIONS OF FLOW AND WEATHER BY FULLY AUTOMATIC MEANS.
- DURABILITY AND FREEDOM FROM MAINTENANCE PROBLEMS.
- ECONOMY OF TOTAL LIFE-CYCLE COST FOR THE LIFE OF THE FACILITY (50 YEARS).
- CONTROLLABILITY OVER THE RANGE OF OPERATIONAL FLOW CONDITIONS.
- ABILITY TO PASS ICE AND DEBRIS.
- SURVIVABILITY UNDER EXTREME FLOOD CONDITIONS.
- PORTABILITY AS A COMPLETELY CHECKED-OUT AND PRE-ASSEMBLED UNIT READY TO BE INSTALLED.
- DEMONSTRATED PERFORMANCE UNDER ALL EXTREME AND NORMAL OPERATING CONDITIONS.

FIGURE 4

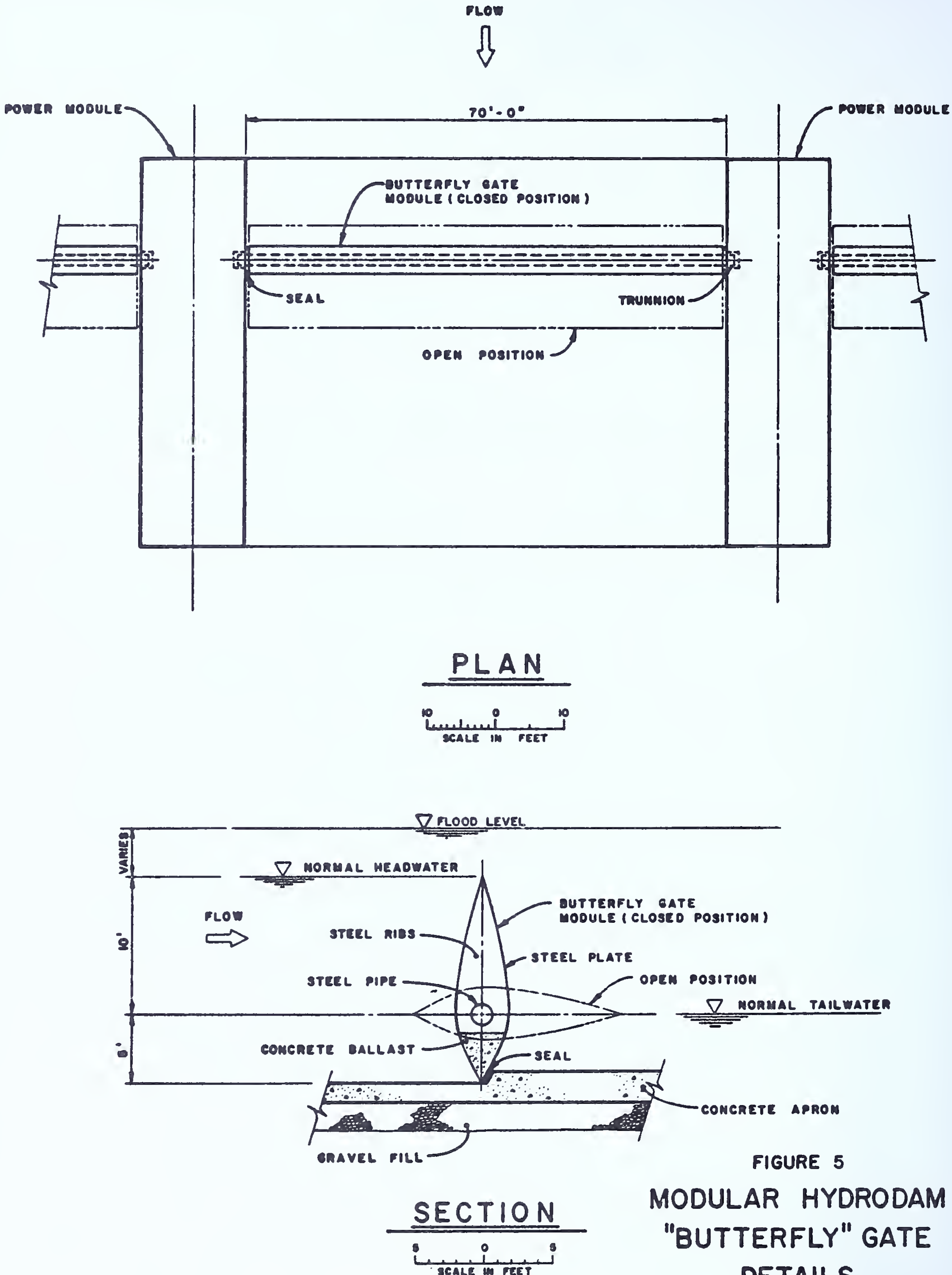


FIGURE 5
MODULAR HYDRODAM
"BUTTERFLY" GATE
DETAILS

MODULAR HYDRO DAM
PRE-FEASIBILITY COST ESTIMATE

ITEM	AXIAL FLOW TURBINE FABRIC DAM	CROSS FLOW TURBINE FABRIC DAM
MOBILIZATION & DEMOBILIZATION	$ 20,000	$ 20,000
SITE WORK	120,000	120,000
COFFERDAM	-	-
TURBINE/GENERATOR UNITS	1,822,000	4,410,000
DAM	1,780,000	2,220,000
SUPPORT CABLE	280,000	280,000
SWITCHYARD	80,000	80,000
SUB-TOTAL	$4,102,000	$7,130,000
CONTINGENCY	940,000	1,220,000
SUB-TOTAL	$5,042,000	$8,350,000
ENGINEERING & OWNER'S COST	870,000	1,140,000
TOTAL	$5,912,000	$9,490,000
INSTALLED CAPACITY KW	1310	1232
$/KW	$4,510/KW	$7,700/KW

ASSUMPTIONS:

- 1981 DOLLARS
- AVERAGE SITE CONDITIONS
- 500 FT. WIDE RIVER - AVG. ANNUAL FLOW 2000 CFS
- 10 FT. NOMINAL HEAD
- CONSTRUCTION IN THE WET

FIGURE 6

PENNSYLVANIA P.U.R.P.A. PANEL

RICHARD SANDUSKY

Mr. Sandusky holds a B.S. in Civil Engineering and a Masters in Public Administration and Policy, both from Carnegie - Mellon University.

Currently Rich serves as the Chief of the Research, Development and New Energy Technology Section in the Bureau of Conservation Economics and Energy Planning (C.E.E.P) of the Pennsylvania Public Utilities Commission. He joined the Commission in 1977 as a technical advisor to the Office of the Administrative Law Judge and joined C.E.E.P in 1978.

Prior to attending graduate school and joining the Commission, he served as a First Lieutenant in the U.S. Army Corps of Engineers.

Rich serving as Chairman of a panel consisting of William Ferguson and William Wilson of the National Conference of State Legislatures and the Energy Law Institute respectively, discussed in detail the Pennsylvania position on PURPA. He also called attention to the pioneer rate of $0.06 per KWH of the Pennsylvania Power and Light Company for purchases of net electric energy output of qualifying facilities made prior to January 1, 1990. The effective date for this rate, unless otherwise contested, would be June 15, 1981.

In lieu of a verbatim report of the panel, a copy of the Proposed Regulations for the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978 of the Pennsylvania Public Utilities Commission follows. The order proposing the regulations and Appendix A setting forth definitions of "Qualifying Facilities" published at 45 FR 17972-17974 (March 20, 1980) etc., have been intentionally omitted to conserve space in this volume.

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17120

Public Meeting held

Commissioners Present:
Susan M. Shanaman, Chairman
Michael Johnson
James H. Cawley
Linda C. Taliaferro

Proposed Regulations for the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978.

O R D E R

BY THE COMMISSION:

As part of an overall policy of directing the prudent use of energy resources in this country, five statutues, grouped as a National Energy Act, were enacted into law in 1978. One of the five statutes is the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, Nov. 9, 1978, 92 Stat. 3119 (codified in scattered sections of 15, 16, 30, 42 and 43 U.S.C.). Specifically, Pub. L. 95-617, Title II, §210, Nov. 9, 1978, 92 Stat. 3144; 16 U.S.C. §824a-3(a)-(j) (commonly referred to as Section 210), pertains to utilities offering to sell electric energy to, and purchase electric energy from, "qualifying facilities," That section required that the Federal Energy Regulatory Commission (FERC) promulgate rules defining "qualifying facilities" and otherwise implementing the statute. Section 210 also required that each state regulatory commission and each non-regulated electric utility must, after notice and opportunity for hearing, develop procedures by which it intends to implement the FERC's rules within one year of their issuance.

On February 19, 1980, FERC issued its final rules for the implementation of Section 210. The enactment of PURPA, and subsequent promulgation of the FERC rules, require that this Commission consider the effects thereof on electric utilities, ratepayers and qualifying facilities in Pennsylvania. Pursuant to that consideration, we are by this Order promulgating proposed regulations, contained in Annex A. These regulations are intended to establish a balance approach which will both encourage the production of electrical energy by small power production and cogeneration facilities and provide benefits to Pennsylvania's utilities and their customers. Comments are encouraged from utilities, qualifying facilities, and all other interested parties concerning changes, deletion, and/or additions to these regulations.

In addition, the Commission solicits responses to the following questions:

1) Should the Commission prescribe a standard format for the annual submission of utility data and should the data be submitted in machine readable (i.e., punched cards of magnetic tape) form?

2) Should the Commission allow combined data filings for utilities on the basis of membership in power pools or reliability councils? What power pool data, if any, should be filed with the Commission?

3) Should the Commission require utilities to establish standard rates for qualifying facilities whose capacity is greater than 100 kilowatts?

4) Should the Commission require utilities to establish transmission or wheeling rates?

5) Should the Commission develop and/or prescribe a specific methodology for determing utilities' avoided energy and capacity costs?

The proposed regulations plus the comments received will be used as the basis for discussion in public hearings that will be held in the near future. After these hearings, the Commission will then issue final regulations.

Comments (the original plus eight copies) should be submitted to Secretary William P. Thierfelder, Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, PA 17120. Comments are due 45 days after publication in the Pennsylvania Bulletin.

To aid in the interpretation of these regulations and the development of meaningful comments, the Commission feels that it is appropriate to provide some supplemental information to help to illustrate the intent of various parts of these regulations. To this end we have included the following comments on a section by section basis.

§57.31 - Definitions

Little explanation is needed here; most of the definitions used are identical to those used in the FERC's final rules or elsewhere in the Commissions regulations. We have however choosen for convenience to include a separate Appendix A which defines qualifying facilities. This appendix simply sets out the requirements that a qualifying facility must meet as established by the FERC in its final regulations in 45 F.R. 17972-17974 (March 20, 1980) and as amended in 45 F.R. 33603-33604 (May 20, 1980), 45 F.R. 33964 (May 21, 1980), 45 F.R. 52780 (August 8, 1980), 45 F.R. 66789 (October 8, 1980), and 46 F.R. 11253 (February 6, 1981).

We have also chosen to elaborate here upon the term "avoided costs" because of its critical nature in terms of the effect it will have on the development of qualifying facilities.

"Avoided costs" are defined as the incremental costs to an electric utility of energy or capacity or both, which, but for the purchase from a qualifying facility, the electric utility would generate

or construct itself or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in Section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent primarily the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to generate and deliver energy; they consist primarily of the capital costs of facilities.

If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase from a qualifying facility will be based on the avoided capacity and energy costs.

The Commission has included the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. Subject to operating restrictions, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. Therefore, the utility's avoided incremental costs (and not average system costs) should be used to calculate its avoided costs. Similarly, with regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used.

§57.32 - Purpose And Scope

Subsection (a) has been included to make it clear that the provisions of these regulations are simply an option that is available for qualifying facilities to take advantage of if they so choose.

Subsection (b) defines the scope of these regulations as encompassing all of the regulations pertaining to the purchases and sales of energy or energy and capacity between qualifying facilities and electric utilities. The utility cost data that must be filed, the factors that must be considered in establishing rates for purchases and sales, and other provisions included in these regulations are designed

to provide the information needed to estimate a utility's avoided cost and to outline both the principal factors that the Commission will consider and the procedure that will be followed if a qualifying facility requests that the Commission establish a rate at which a utility must purchase the qualifying facility's energy or energy and capacity.

However, it is anticipated that in many cases, using the same data and guidelines, qualifying facilities and utilities should independently be able to determine an appropriate rate or rates which are agreeable to both parties. In such cases, where the qualifying facility and utility are willing to enter into a mutually agreeable contract, there is no need for the Commission to intervene. For this reason, subsection (c) of the section has been included to make it clear that the provisions of these regulations apply only if a qualifying facility chooses to avail itself of them. The right of a qualifying facility to negotiate and enter into an agreement or contract with an electric utility shall not be superseded by the provisions of these regulations. Utilities will however be required to file a copy of any such contract or agreement with the Commission.

Section 57.33 - System Cost Data To Be Filed By Electric Utilities

This section outlines the data that utilities will be required to file with the Commission and make available to the general public. While similar to the data requirements promulgated by the FERC in its rules, the Commission has decided to make use of the option which allows the Commission to establish its own data filing requirements. The principal differences between FERC's requirements and those proposed by the Commission are that the utilities will be required to submit the prescribed data annually rather than once every two years and that the utilities will be required to include their cost assumptions and a description of the methodology used to estimate their projected costs.

The primary purpose of making this data available is to provide the basic information that the Commission or a potential qualifying facility developer would need to estimate a utility's avoided cost. The Commission feels that this information should be as timely as is possible. Therefore, to balance the effects of inflation and to provide a means of determining the effects of unforeseen escalations of fuel prices, the Commission has chosen to require an annual filing which specifies the fuel prices and other important factors that were used to develop the utilities' estimates of their costs.

Subsection (a) specifies which jurisdictional utilities will be required to file data on an annual basis.

Subsection (b) specifies, in detail, the data that must be filed with the Commission and made available to the public. To allow a potential developer of a qualifying facility to determine the financial viability of any project, it is essential that they be able to estimate what a utility's avoided cost will be so that they can attempt to negotiate a reasonable rate with the utility. Furthermore since the qualifying facility has the option of offering to sell energy only or energy

and capacity, it is important that the necessary information to calculate the appropriate avoided cost figure for either of these cases be readily available. Subparagraph (i) outlines the data which should be sufficient to allow individuals to establish a utility's avoided energy costs and subparagraphs (ii) and (iii) detail the information necessary to estimate an avoided cost rate for purchases of energy and capacity.

While the filing of this data does not impose an unreasonable burden upon those utilities whose generation exceeds the 500 million kilowatt-hour limit established in subsection (a), the Commission recognizes that for smaller utilities and those utilities that do not generate their own power, the requirements of subsection (b) of this section may be inappropriate. Therefore subsections (c) and (d) provide that utilities with generation below the 500 million kilowatt-hour limit will be required to provide this type of information only upon request and that distributional utilities may simply use the data filed by their supplying utilities.

Section 57.34 - Purchases From Qualifying Facilities

Subsection (a) provides general requirements that apply to purchases of energy or energy and capacity from qualifying facilities. It requires utilities to purchase any energy and capacity that is offered subject to the conditions contained in the applicable statutes and regulations. Included are the conditions that the rate is just and reasonable from the purchasing utility's ratepayers' perspective, that the rate does not discriminate against the qualifying facility, and that the rate does not exceed the utility's avoided cost. These conditions insure that no party, i.e. the ratepayers, the qualifying facility or the purchasing utility is unfairly disadvantaged by the rates that are established for any purchase.

Subsection (b) provides that rates for purchases of energy only may be based upon either an estimate of or the actual avoided costs of the utility at the time that the energy is delivered. For qualifying facilities which produce large amounts of energy, the installation of meters which record both the time and amount of energy supplied may be a cost effective way of matching the output of the qualifying facility to the utility's actual avoided cost. However, for small qualifying facilities, the cost of this type of metering equipment may be prohibitive. Therefore to allow flexibility, a qualifying facility may elect to receive payment at a rate that reflects the "average" avoided cost of the purchasing utility during the time period, i.e. daily, weekly, monthly, etc. that energy is supplied. This paragraph also emphasizes that the avoided costs of the utility which are used to determine what the qualifying facility will receive for the energy it supplies to the utility must include more than just the cost of fuel. All other incremental expenses such as reduced incremental operations and maintenance expenses, reductions in working capital from fuel inventories, etc. must also be included.

Subsection (c) contains the guidelines for rates for purchases of both energy and capacity. Subparagraph (i) gives the qualifying facility the option of receiving either whatever the utility's actual

avoided cost is at the time of delivery in the future or a pre-established rate which is based upon today's estimate of what the avoided cost will be at that time. While it can be safely assumed that energy prices will continue to rise, the developer of a qualifying facility may be willing to trade off potentially higher profits for a measure of certainty concerning the rate that it will receive for the energy and capacity that it supplies over the life of the agreement that it enters into with the utility. This set price (which may include a fuel adjustment or inflation escalator) may also make the financing of these projects easier in that the lender will know what the qualifying facility will receive. Furthermore, allowing a utility to establish a prospective rate may help to stimulate the development of additional projects. Therefore the Commission feels that both options should be available.

Paragraph (2) outlines the specific items to be considered when establishing a rate for purchases of energy and capacity. Emphasis has been placed on insuring that the capacity offered must meet the utility's needs in terms of the utility's need for capacity, the reliability of the capacity, and the degree of control that the utility has over the capacity. If a qualifying facility offers a utility capacity for a period of time during which the utility will not need to make any capacity additions to its system, the utility will not be avoiding any costs. Only where a utility can eliminate or defer the construction of new facilities is a capacity credit or payment appropriate. When such a credit is appropriate, it should reflect the usefulness of the capacity to the utility. Whether the capacity is available during peak periods, its reliability in terms of availability (i.e., projected outage rates), and the ability of the utility to dispatch capacity during both normal and emergency operating conditions, are all factors that must be considered. These requirements are necessary to insure that the utility's obligation to provide safe, adequate, and continuous service to its customers can be met. Similarly, factors such as credit for both individual and aggregate capacity, shorter construction lead times, smaller capacity increments, and reduced transmission line losses must also be considered. These represent some of the principal advantages of qualifying facilities which can have positive effects on the purchasing utility's system.

Subsection (e) has been included to clearly state the Commission's position on whether a qualifying facility can sell all or only a part of its output. Some parties have stated that the regulations issued by the FERC were ambiguous on this point, therefore this paragraph has been included in this Commission's regulations to eliminate all doubt about whether or not qualifying facilities have this option.

Subsection (f) requires that each utility must file with the Commission a standard tariff or tariffs which applies to purchases from qualifying facilities with a design capacity of 100 kilowatts or less. This provision, which is required by the regulations issued by the FERC, recognizes that even with the cost information that the utilities will be required to make available to the public, some developers or owners of small qualifying facilities will have difficulty determining a utility's avoided cost. Therefore to ease this burden, standard rates

for these smaller qualifying facilities are necessary. Utilities may also choose to file standard rates for larger qualifying facilities. These filings will be reviewed on a case by case basis by the Commission, however at this time utilities will not be required to file standard rates for qualifying facilities whose design capacity is greater than 100 kilowatts.

Subsection (g) requires that rates for purchases from "new" qualifying facilities (construction of which started on or after November 9, 1978) must conform to the requirements outlined in paragraphs (a), (b), and (c), but allows the rates for "old" (pre-November 9, 1978) facilities to be set at a rate below the utility's avoided cost. The rationale for this differentiation lies in the fact that old qualifying facilities which were operating or under construction prior to the passage of PURPA, already had all the financial incentive that was required and no additional incentive was needed. However because the profitability of these facilities can change due to differences between actual and projected operating performance, changes in cost of fuels, etc. it is possible that these old facilities may need to avail themselves of the avoided cost provisions of these regulations to remain profitable and continue to operate. Therefore it is the position of this Commission that qualifying facilities built or under construction prior to November 9, 1978 shall be eligible to take advantage of the provisions of these regulations if it can be shown by the qualifying facility that a lower rate is not sufficient to encourage the continued operation of the qualifying facility. Nothing in these regulations however is to be construed as to require a utility to pay a rate in excess of what it is paying under the terms of a legally enforceable contract that it has entered into with such a qualifying facility.

Subsection (h) has been included to provide a procedure whereby the utility can discontinue its purchases in recognition of the fact that there may be periods where purchases from a qualifying facility or facilities could increase the net operating costs of the purchasing utility. This provision covers the situation that could occur when a utility which is operating only base load units during a light loading period would have to reduce the output or shutdown a base load unit in order to purchase energy from a qualifying facility or facilities and then have to use a faster starting but more expensive unit to meet increases in load because the base load unit could not be restarted or its output increased rapidly enough to meet the increasing load. However, to insure that the qualifying facility is not placed at a disadvantage, the affected utility must provide adequate notice. If it fails to do so, the utility will be required to meet the provisions of and pay the appropriate rate outlined in the preceeding sections of these regulations.

Section 57.35 - Sales To Qualifying Facilities

This section is intended to ensure that any qualifying facility will be able to obtain service from the utility within whose service territory it is located. The provisions of subsection (a) require that the rates for sales to qualifying facilities should be the same for a qualifying facility as they are for any other customer with

similar load characteristics. For example, a residential customer with a windmill would be served under the appropriate residential service tariff and a commercial or industrial cogenerator would be served under the same tariff that a similar commercial or industrial customer without cogeneration would be served under.

Subsection (b) requires each utility to provide upon request supplementary, back-up, maintenance, and/or interruptible power. One or more of these services may be necessary depending on the type of qualifying facility and whether it sells all or only part of its output to the purchasing utility. To eliminate the potential situation where a qualifying facility may be faced with an unreasonable demand or capacity charge for back-up or maintenance power, subsections (c) and (d) provide specific guidance on how these rates should be set. Back-up rates must be adjusted to reflect the fact that outages by all of the qualifying facilities on a single utility's system will not occur simultaneously or during the system's peak. This adjustment should be based on probability analyses using past operating experience and/or projected performance data. For maintenance power, no demand charge will be permitted if the qualifying facility is willing and the purchasing utility is able to coordinate scheduled outages. The rationale for this is simple; if the qualifying facility only places a demand on the utility's system during periods of low demand, the utility does not have to build additional capacity which would be solely for the purposes of meeting the qualifying facility's demand. Therefore no demand charge is warranted.

Section 57.36 - Interconnection Costs

This section outlines the responsibilities of a qualifying facility in the area of interconnection costs. Subsection (a) states that each qualifying facility must bear the expense of any additional costs that the utility incurs so that the utility can purchase power from the qualifying facility. Each qualifying facility will however have the option of supplying whatever equipment is required itself rather than having the utility provide it so long as the equipment is compatible with the purchasing utility's equipment. If it selects this option, the qualifying facility must submit its plans to the utility prior to the installation of the equipment. Upon receipt, the utility will then have 30 days to approve or disapprove the plans. To simplify this process and to encourage standardization, utilities should also provide general interconnection plans and requirements when possible.

Because the economics of each project and the relative percentage of total project costs that interconnection costs may constitute varies substantially, the qualifying facility shall have the option of paying for the additional interconnection costs in one lump sum payment or in a number of payments over time. This will allow projects that are capital intensive to spread this cost out over time. If however the qualifying facility elects to spread these costs out over time, it must also pay any carrying charges that reflect the utility's cost of capital.

Section 57.37 - Standards for System Safety and Reliability

This section allows utilities to establish reasonable standards governing system safety and reliability to provide for the safety of

utility personnel and the general public and to assure reliable service to utility customers. However any standards that a utility files will be subject to Commission review, and it will be the responsibility of the utility to file supporting documentation which demonstrates the need for such standards.

Section 57.38 - Informal Consultation and Commission Proceedings

These regulations are intended to encourage mutually agreeable contracts between qualifying facilities and electric utilities. For these cases the Commission has decided to establish an informal consultation process.

The first step, after the qualifying facility fails to reach an agreement with the affected utility, is for the qualifying facility or utility to file a petition including the information outlined in subsection (a) of this section with the Commission. An attempt will then be made by the Commission staff to resolve any misunderstandings and, where appropriate, suggest possible solutions which are fair to both the qualifying facility and the utility. If successful, it is anticpated that both parties will enter into an agreement and the Commission's involvement will end there.

Where the problem cannot be resolved or the qualifying facility chooses not to take advantage of the informal process, the qualifying facility may file a formal complaint. This complaint will then be heard by an administrative law judge who will issue a decision which will set the rate that the qualifying facility will receive. Such decision will be subject to Commission review in accordance with the terms of the Public Utility Code, 66 Pa. C.S. §§101 et seq.

For the reasons set forth above, this Commission has determined that it is appropriate at this time to open a proposed rule making docket and that the proposed regulations in Annex A be published for comment.

It should be noted that the Commission is also proposing the elimination of 52 Pa. Code §57.31 which was promulgated under Section 418 of the Public Utility Law (66 P.S. §1188). This is because the matter is now controlled by Act 57 (15 P.S. §32.77). Therefore, to update our regulation and to make room for the new regulations to implement Section 210 of PURPA, we have chosen to combine these two actions.

Accordingly, pursuant to Sections 501, 504, 505, 506, 507, 508, and 1301 of the Public Utility Code (66 Pa. C.S. §§501, 504, 505, 506, 507, 508, and 1301); §§201 and 202 of the Act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§1201 and 1202); and the regulations at

1 Pa. Code §§7.1 and 7.2, we propose adoption of the regulations set forth at Annex A, or those regulations as modified after receipt of comments; THEREFORE,

IT IS ORDERED:

1. That a proposed rule making docket be opened and that this order, together with Annex A and Appendix A be published in the Pennsylvania Bulletin.

2. That the Secretary shall submit this order to the Office of Attorney General for preliminary review as to legality.

3. That the Secretary shall duly certify this order and deposit same with the Legislative Reference Bureau.

4. That comments (original and eight copies) concerning the regulations proposed in Annex A may be submitted within forty-five (45) days of their publication in the Pennsylvania Bulletin. Comments should be addressed to the Pennsylvania Public Utility Commission, Attention: Secretary, P.O. Box 3265, Harrisburg, PA 17120.

BY THE COMMISSION,

William P. Thierfelder
Secretary

(SEAL)

ORDER ADOPTED:

ORDER ENTERED:

INTRODUCTION TO PURPA PANEL

1981 Hydropower Conference

Eric M. Page, an Assistant Attorney General, first introduced himself as a representative of the Division of Consumer Counsel of the Office of the Attorney General. The Division represents consumers in utility cases before the State Corporation Commission. These cases include questions concerning rates, service, rulemaking and other regulatory matters.

Mr. Page then discussed the Public Utility Regulatory Policies Act of 1978 (PURPA). Generally, this legislation is one of five portions of the National Energy Act, signed into law by President Carter on November 9, 1978. As expressed in the Act, Congress intended three goals: conservation of energy; optimally efficient use of utility resources and facilities; and, equitable rates to customers. PURPA sets forth federal standards to carry out these purposes, and directs state utility commissions to accomplish a number of goals and consider standards according to a stated timetable.

Specifically, § 210 of PURPA deals with cogeneration and small power production. Section 201 defines a cogeneration facility as a facility which produces electric energy and steam or heat as a by-product to be used for industrial, commercial, heating or cooling purposes. A small power

production facility is a facility which produces electric energy solely by use of biomass, waste, renewable resources or any combination, provided the capacity is less than 80 megawatts. Qualifying facilities, on the other hand, are small power production and cogeneration facilities which are determined to comply with certain Federal Energy Regulatory Commission (FERC) definitions. The major criteria provides that a qualifying facility owner not be primarily engaged in the production or transmission of electricity. In addition, PURPA requires state commissions to promulgate rules and regulations for qualifying facilities of under 100 kw capacity, and allows their discretion to do so for qualifying facilities of over 100 kw capacity.

The purpose of § 210 of PURPA is to encourage cogeneration and small power production by eliminating certain historic obstacles to the existence of these facilities. First, PURPA obligates electric utilities to purchase power from qualifying facilities at rates set by the state regulatory commission, thus providing an incentive through costs. Second, utilities are required to provide standby power to qualifying facilities at non-discriminatory rates. Finally, § 210 exempts qualifying facilities themselves from state and federal regulation of utility rates and practices. It is important to realize, Page stressed, that nothing determined by the state regulatory commission can affect the validity of a contract between a qualifying facility and a utility.

Pursuant to PURPA, the FERC promulgated rules and regulations effective March 20, 1980 to implement PURPA § 210. The crucial issue considered by the FERC was the price that the utility must pay for power generated by a qualifying facility. PURPA requires that rates for purchase by a utility may not exceed the incremental cost to the electric utility of alternative electric production. In the FERC's final rule implementing this section, incremental cost is defined as avoided cost; that is, the cost to an electric utility which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself for purchase from another source. This has also been referred to as the utility's marginal cost of generation. Avoided costs have two components: first, is the energy cost, or the measure of the cost of the fuel the utility saves by using the qualifying facility's power. Second, is the capacity cost, the estimated savings to the utility by avoiding capital construction or the cost of purchased power.

Mr. Page then discussed implementation of PURPA in Virginia. The Act requires state agencies to implement the FERC rules regarding cogeneration and small power production by March 20, 1981. Pursuant to this mandate, the Virginia State Corporation Commission (Commission) gave notice and held public hearings for each Virginia electric utility in January, 1981. Seven hearings were held: five involving

Virginia's generating electric utilities (Virginia Electric and Power Company, Appalachian Power Company, Potomac Edison Company, Potomac Electric Power Company, and Delmarva Power and Light Company). One case involved Old Dominion Power Company, a utility which does not generate its own electricity but sells power generated by a parent company. And, one case was heard to consider rates for customers of Virginia's 14 electric cooperatives.

Each company was directed to pre-file avoided costs, proposed schedules and supporting data and testimony. The Division of Consumer Counsel participated in each case, presenting expert testimony in five of them, advocating the interests of consumers of each utility. Mr. Page coordinated the Division's case in each instance. Other participants in the cases included a group of industrial customers, residential consumers, and in three of the hearings, the Virginia Hydropower Association was represented by counsel.

The cases were heard by hearing examiners, who gathered evidence and filed their reports in early March. Parties were given an opportunity to respond, and these documents are now before the three commissioners who must decide the outcome of the cases.

The reports of the hearing examiners recommend certain rules and regulations that the Commission should adopt in implementing PURPA § 210. The crucial section deals with the requirement that utilities should pay a qualifying

facility its full avoided cost. In all but one case, the hearing examiners found that the utility had reasonably determined its avoided costs. In the case of the electric cooperatives and Old Dominion Power Company, the hearing examiner found that avoided costs equal the wholesale power rate these companies pay to their suppliers. Mr. Page then listed the proposed 1981 avoided energy costs for each of the remaining electric utilities:

Avoided Energy Costs
(per kwh)

	On-Peak	Intermediate	Off-Peak
Appalachian Power Co.	1.29¢		1.17¢
Virginia Electric and Power Co.	Summer 3.717¢ Winter 3.150¢		2.297¢ 2.297¢
Delmarva Power and Light Co.	Summer 6.37¢ Winter 6.25¢		3.16¢ 3.73¢
Potomac Electric and Power Co.	Summer 5.484¢ Winter 5.078¢	3.428¢ 4.201¢	2.346¢ 2.632¢
Potomac Edison Co.	1.57¢		1.57¢
Old Dominion Power Co.	1.39¢		1.39¢

The hearing examiner in the Virginia Electric and Power Company (VEPCO) case recommended that another hearing be held to determine the appropriateness of VEPCO's avoided costs. This recommendation resulted from an update submitted by the company after the hearing pursuant to an updated marginal cost study.

Each utility filed proposed rates regarding avoided capacity costs. These costs varied, according to the capacity each utility plans to bring on line over the next few years. For both avoided capacity and energy costs, the hearing examiners recommended that utilities be required to update their figures annually.

Another important issue, pointed out by Mr. Page, is that the Commission will act as a arbiter with respect to any negotiations between a qualifying facility and a utility. The Division of Consumer Counsel has urged the Commission to use the rates for purchases from and sales to a qualifying facility derived through the PURPA hearings to act as the basis for negotiations between the qualifying facility and the utility.

Mr. Page then introduced the four panelists:

Conrad Desieno: Assistant Vice President, Rate Research and Design for the American Electric Power Service Corporation. Mr. Desieno has worked with American Electric for 30 years in Systems Planning. In 1978, he was appointed Vice-President and Chief Planning Engineer for Regional Power Supply.

Johnny Barr: Director of Cost Analysis for Virginia Electric Power Company. He has been with the company since 1974.

John Pollock: Mr. Pollock is the president of North American Hydro, Chairman of the Virginia Hydropower Association, and of the Nelson County Board of Supervisors.

Britt Gilbert: Mr. Gilbert is the developer of the Woodstock and Edinburg dams. The former dam will generate 400 kw, and will be the first project which will sell electricity to a utility in Virginia.

QUESTION: "Why should hydropower be treated differently from other forms of small power production?"

ANSWER: (Britt Gilbert)

"Up to the present, all types of small power production have pretty much been lumped together in the PURPA hearings. This ignores one basic difference between hydro and, say, biomass fueled projects. That is the difference in whether operating cost is mostly debt service or mostly fuel cost.

For instance, I'm working on a biomass fueled project in North Carolina. On a project like this the capital cost is low, but the daily fuel cost is fairly high. The total operating cost is probably three-fourths fuel. Now, as you all probably know, the North Carolina Public Service Commission has ordered the utilities to pay levelized pricing for long term contracts with small power producers starting at very high rates in the early years and dropping in real dollars, mostly because of inflation.'

If I could get the P.S.C. to order Vepco to buy all the power I could make at this project for 12¢ a kilowatt-hour, I'd make money hand-over-fist for the first five or six years of the twenty year contract. But, just as soon as the daily cost of the fuel got to be a burden, I'd quit buying it; halfway through the contract I'd be listening to Brazilian music.

On the other hand, a hydro project requires an intensive capital investment at the outset of the project. The machinery is fixed and cannot easily be moved. The utility has the security of knowing the hydro project will not be abandoned and the operator will fulfill the terms of the contract. Such security is not certain with a project with high, on-going fuel costs, often approximating three-fourths of the operating costs. The developer of the fuel intensive operation can afford to sell electricity until the cost of his fuel is prohibitive, then junk his equipment and shut down his operation and go to Brazil.

Thus, a hydro-project could be compensated for its dependability by receiving preferential rates, which, in turn, will give the utility the security of a long-term source of power production. That's insurance for the utility."

ECONOMICS OF HYDRO DEVELOPMENT

AND B/C RATIO

Dilip R. Limaye
Thomas Hough

Mr. Dilip R. Limaye is president of the Synergic Resources Corporation (SRC) in Bala-Cynwyd, Pennsylvania. In keeping with the definition of the company name they have worked together with engineering firms, site developers, equipment manufacturers, and others to pioneer and develop computer programs for evaluation of hydropower development.

Mr. Limaye has directed the SRC development of analysis models and economic feasibility studies of Flat Rock Dam and other hydro sites in Pennsylvania. Currently models are being developed for the Inter American Bank for small hydropower analysis in Latin America.

Mr. Thomas Hough, manager of Hydropower studies for SRC,is a native of Pennsylvania.

It is my pleasure to be here today and I apologize on behalf of Tom Hough, who was supposed to be here speaking on the subject.

The firm I represent, Synergic Resources Corporation, is a consulting firm, and we have been involved in hydropower studies in Pennsylvania for the last two or three years. We started a few years ago working with Larry Gleeson, who many of you know and who is somewhere in the back of this room, on the Flat Rock Dam project in Philadelphia. At that time, hydropower was fairly new and if somebody would have said to me, "Hey, we're going to generate hydropower in the City of Philadelphia," I would have said that they were crazy. As it turns out, the Flat Rock Dam is owned by the Pennsylvania Department of Environmental Resources and is located right on the boundary of the City of Philadelphia. It is about a 16 foot high dam, and our preliminary studies of almost 2½ years ago showed that it could be economically feasible to develop hydropower there. In fact, we did some preliminary studies and then completed a full-scale feasibility which was used as justification for an application to DOE for a demonstration grant which was awarded. We are hoping that sometime in the future we will see some construction at that site which would lead to the development of about 3½ megawatts of power right in the City of Philadelphia.

Since that time, we've been getting more and more interested and involved in hydropower studies. There are many sites where hydropower was produced in this country many years ago. Then, as power generation at the central station became cheaper and cheaper, we lost a lot of these hydro sites, and it appears that they may be coming back now. The reason they're coming back is that some of this water flowing over the dam represents useful energy flowing over the dam; looking at it from another perspective, it is basically money flowing over the dam that can be beneficially used.

During this seminar, you've heard a lot about hydropower, about the engineering aspects, the various turbines and technologies, the regulations, the PURPA rates and so forth. From the point of view of a developer of hydro, it all boils down to this: What does it mean in terms of economics? What we're going to talk about for the next few minutes are issues related to the economic analysis of hydropower and how to evaluate the economic feasibility of hydro sites. The objectives of our work so far has been to develop a comprehensive framework which is supported by a set of computer models. We can look at all aspects of a hydro site and evaluate the bottom line. What are the economics, what is the financial feasibility, what are the cash flows and rates of return, and so forth.

In order to do that, you have to look at a number of aspects. Obviously, engineering is important; you have to look at the technologies available, the site characteristics, how you're going to match the turbines to your site requirements. The economic aspects include the markets that you have for the power and the cost of developing the site. The environmental aspects -- is someone going to ask you to put a fish ladder on your site; are white-water canoeists going to object to your interfering with their canoeing? The institutional aspects involve some of the things you just heard: how are you going to sign contracts with utility; what are going to be the terms of the contract? What rates will you receive? By regulation, if you are a small site and you qualify as a small power producer under PURPA, you will not have to worry too much about regulation. The financing aspects -- I guess the two speakers following me will probably cover in great detail -- but there are various options available for financing hydro sites, which must be addressed in this feasibility evaluation. The evaluation framework has been developed by SRC and used in Pennsylvania initially for the Flat Rock Dam and later for feasibility studies for about half-dozen other sites. We have also prepared a report identifying a number of other sites in Pennsylvania. I will make sure that Ed Gray gets enough copies of the report that he can send them to you with the proceedings of this conference.

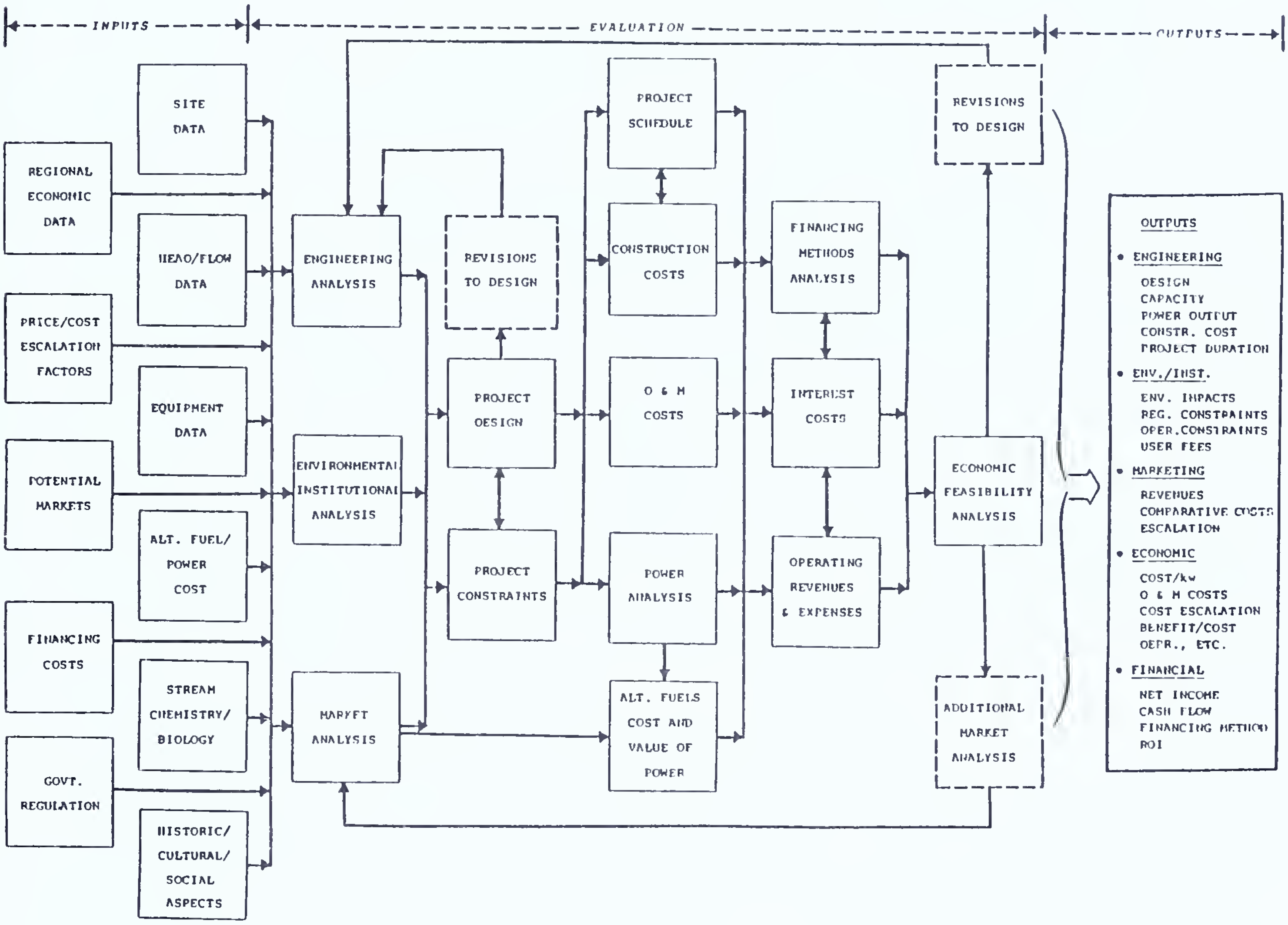
The economic analysis is important in various stages for the project design and project evaluation. The very first stage is in doing a site reconnaissance or a very preliminary assessment of the site. At this stage you are looking for a very "quick and dirty" kind of economic analysis. The next step might be a preliminary feasibility study which you may want to do at the time of the permit application. Then you go to a full-scale feasibility study, and as you are going along these steps, the information requirements and detail increase. The full-scale feasibility study would determine your course of action. The next step then is the licensing process; and here again you have to prepare a number of exhibits and documents to satisfy FERC. If it is indeed a viable site, and you are a viable applicant then, finally, you get into the construction.

The approach we have used is to develop a framework which can be used with different levels of detail and input at all of these different stages. For example, at the site reconnaissance level what we have done is very similar to what E.G.& G. Idaho is going for DOE. Information is processed quickly to come up with rough estimates of economic feasibility. At the next step you have a little more information; perhaps you have a flow duration curve, or you can do preliminary feasibility studies from using the U.S.G.S. data gage. Later on, as you go into some of the full-scale feasibility studies, you will probably record more information on your market, on what price you're going to get for the power, and some other information regarding construction costs. We will be tracing through one of these examples.

The overall framework looks very complicated in this chart (See Figure 1) but basically, all it's trying to do is to attempt to relate the various aspects of the feasibility study. As I mentioned earlier, these aspects include the engineering aspects, the environmental parts, the design of the project, construction schedule, etc. We'll be going quickly through some of these; I will try to focus in on some of these boxes and show you what they all contain because I know this is going to be a little bit difficult to read from the back. We will, of course, concentrate on the economic issues.

Figure 1

SCHEMATIC OVERVIEW OF
EVALUATION FRAMEWORK FOR HYDROPOWER FEASIBILITY



The first step, of course, in any of this kind of analysis is the engineering analysis. You will require the site information and the information regarding the height of the dam, (or head) and the flow. The flow can be in terms of either a flow duration curve, or perhaps average stream flow which can be relatively easily obtained from the U.S.G.S. We have the ability to take some simple information like mean stream flow and fit a normalized flow duration curve to come up with some rough estimates. Ideally, of course, you want to get detailed information on the flow duration curve.

You also need some equipment data. You need to have information regarding turbine sizes, turbine efficiencies, discharge rates, and so on. Combining all of this information, you can perform an engineering analysis to come up with the power that will be available at the site. This flow duration curve shows the flow at Flat Rock Dam. (See Figure 2) It shows the probability of occurrence of different levels of flow. Translating this into power requires information on turbine efficiencies. Here is some typical information on an Allis-Chalmers turbine that looks at the discharge and efficiency of the turbine as a function of the flow through the turbine. (See Figure 3)

Figure 2

TYPICAL FLOW DURATION CURVE

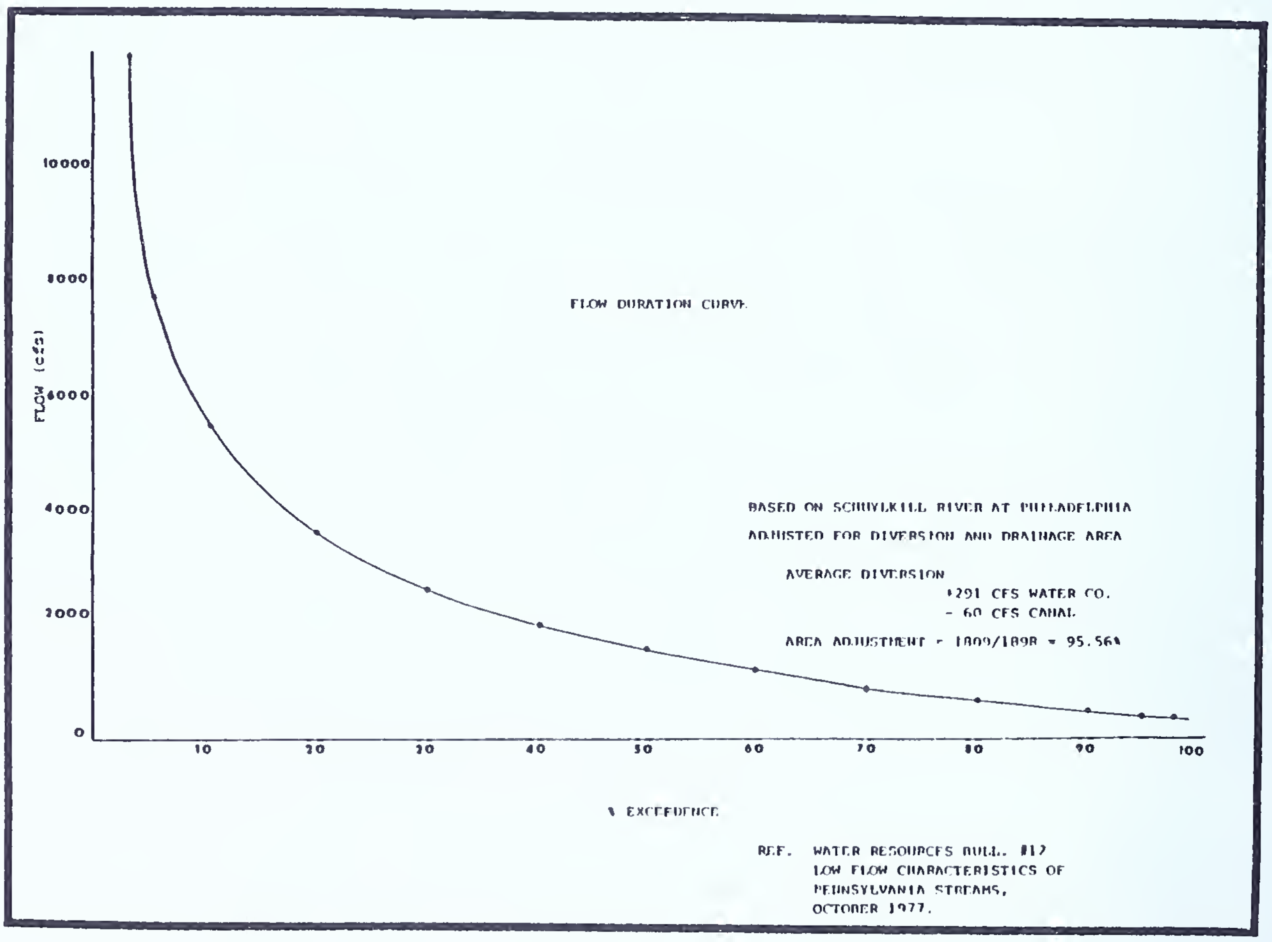
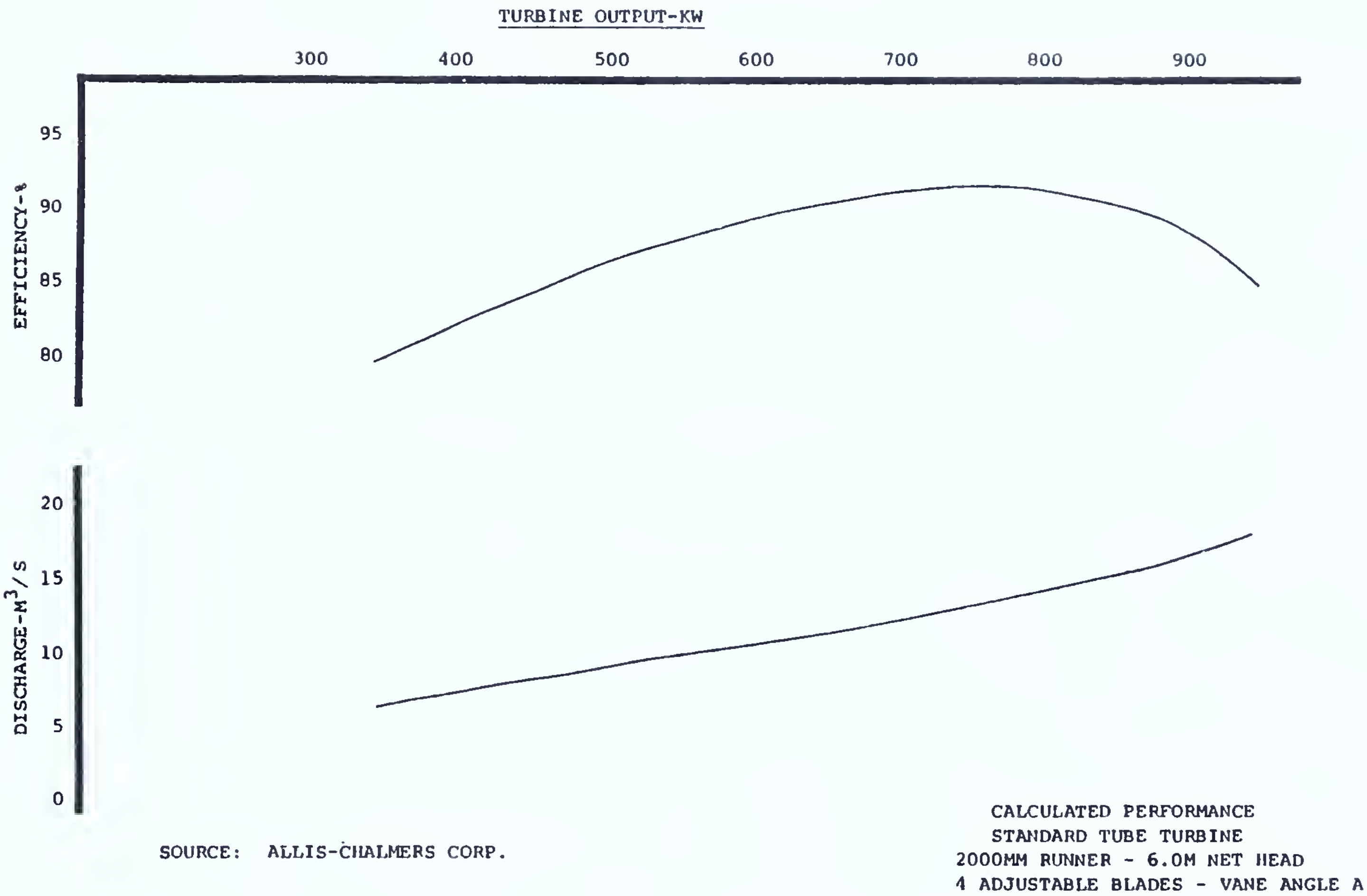


Figure 3

TYPICAL TURBINE PERFORMANCE CHARACTERISTICS



The flow duration curve is translated into a power duration curve. What this gives you is the total amount of power you expect to generate during a given year. There is a strange shape to the curve. The reason for the flat portion on the lefthand side is that the turbines are sized for a maximum amount of flow; if you have more flow than that, it will not flow through the turbines; you're going to waste a certain amount of energy. At the extreme left you see a little dropoff. What happens is that when the flow is very large, the tail water rises up and the head decreases. As a result, even though the flow is equal to the maximum flow, you're losing a little bit of power. As you get smaller and smaller flow through the turbines, you get less power until you reach the point of minimum flow through the turbines. At that point you can't have any power at all. This gives you -- in terms of output -- the information regarding the amount of power to estimate the average annual power availability.

In this particular case, we had something like 19.6 million kwh of power available during the year based on the flow data. The only reason for showing some of this type of output is that when you're doing an engineering analysis like this, you can very quickly look at alternative turbine sizes or alternative equipment configurations. We have the ability to consider up to five different turbines and, essentially, go through an optimization process to determine what types of turbines and how many you should have at the site to generate the most amount of power.

So far we've discussed the engineering analysis. Once we have the numbers of turbines and the type of installation, that will give you the construction cost. What about revenues? This can be very simple if only we had information on the things that were talked about earlier. If we had standard rates, or had projections of these proposed rates over the next few years, then we would know what the revenues are going to be. But that's not quite the case. More often than not you have to negotiate with the utility, you have to figure out what the utility's avoided cost might be in future years. You have to look at the options for future generation cost, and the whole regulatory process that will affect your ability to sell to the utility.

Now in order to do that, you really have to address the utility's perspective. Does the utility have sufficient capacity; if so, they are not very likely to give you any capacity credits. Is the utility basically using oil on the margin? Con Ed right now is 100% oil on the margin, and so are a lot of California utilities. But as was pointed out earlier, some of the Pennsylvania utilities use a lot of coal, so that the energy cost -- the avoided energy cost you're going to get -- will be much less than if they were using oil. Then there's another question. Let's suppose they are using oil. Suppose there's a utility that is using oil 50% of the time and you want to get some benefits of those high energy costs. But what if they have plans to bring on a nuclear or coal plants in the next two or three years, and as a result they are not going to use the oil? Then all of a sudden your avoided energy costs are going to drop. So you have to look at these kinds of things to figure out what your present and future revenue potential is from the sale of energy.

A part of this analysis also involves a look at future fuel prices. Let's suppose the utility does have a mix of oil and coal. What's going to happen to coal prices and oil prices in the future? I guess there have been millions of dollars spent on forecasting prices, and I haven't seen anything yet that is reliable and valid, so essentially you're guessing when you talk about future prices. But you can get a rough estimate. Maybe you can get a range, or you can do an analysis to look at low, medium or high scenario price levels to figure out what your revenue potential is and what your risks are. So, given the power and the market, the next step is to start figuring out what does this all mean in terms of the revenues, costs, and returns. And I thought the best way to illustrate that was to carry you through the case of the Flat Rock Dam, and show you the numbers for that particular project, but please remember that these numbers are about two years old.

The first step, of course, was to get the construction costs. These costs are broken out by the various cost categories as required by the FERC. They include the various cost accounts and the capital costs and the costs per kilowatt are shown in here. (See Figure 4) In addition to the specific construction cost, there is some indirect cost which includes engineering.

In this case, our bottom line was somewhere around 4.4 million dollars for the construction costs. These were estimated at the time the study was done so they were in 1979 dollars. The next step was to look at the escalation of these costs because, as we pointed out earlier, you don't bring on a site instantaenously because of the amount of time required to get through licensing, construction and testing. So one of the things you have to worry about is what's going to happen to these costs over that period of time.

Figure 4

ESTIMATED CAPITAL COSTS OF HYDROPOWER FACILITY AT FLAT ROCK DAM

TWO 3000 MM TUBE TURBINES
MAX. OUTPUT 3.5 MW

FERC Account No.	Description	Cost (In Thousands)	Cost* Per kW
A. DIRECT COSTS			
330	Land & Land Rights	$ 0	$ 0
331	Structures & Improvements	157	44
332	Reservoirs, Dams & Waterways	918	260
333	Turbines & Generators	2,350	666
334	Accessory Electric Equipment	(Included in Account 333)	
335	Miscellaneous Power Plant Equipment	(Included in Account 333)	
336	Roads, Railroads & Bridges	0	0
353	Substation Equipment	(Included in Account 333)	
355	Transmission	168	48
	Total Direct Costs	$3,593	$1,018
B. INDIRECT COSTS			
	Preliminary Engineering Including Assistance w/FERC Application and DOE Proposal	100	
	Detailed Engineering	200	
	Const. Mgt.	150	
	Total Indirect Costs	$ 450	$ 127
	Total Direct and Indirect Costs	$4,043	
	Contingencies	372	105
C. TOTAL CAPITAL COSTS		$4,415	$1,250

*Based on maximum generating capacity of 3.5 MW.

We have a method of calculating the escalation of these costs. We will start off with an estimated initial cost of 4.4 million dollars and multiply it by an escalation rate over this period of time to develop an escalated capital cost. Then there's the question of financing the construction because you have to borrow some money during the construction period, and you have to pay interest on funds used during the construction period. There are some other miscellaneous items that escalate the 4.4 million amount over the two-and-a-half-year construction period, to 5.7 million. So the escalation is a very important part that must be taken into account.

Now we have looked at the engineering to determine power, the market, the project schedule, construction costs, escalated them over a period of time, and now we know what it's going to cost. The next question is, how is this going to be financed? And as I said earlier, there are a number of different methods for financing. In our methodology we have allowed for something like 10 or 12 different types of financing methods.

The first option is your own money, equity. If you can get away without putting any of your own funds into the project you're in good shape. But most financiers will require that you have to have some amount at risk yourself. Then there are different types of financing sources. There was a time when DOE would give you demonstration grants or loans. This may not be happening too much in the future in view of some of the changes that are occurring in Washington. Then there are, of course, conventional financing sources. There is the possibility, if you're a municipality, of getting different types of bonds for financing. You may have municipal bonds or you may have to go into the private market and essentially get private funding.

We have the ability to look at all these different sources and the interest rates on various types of debt instruments. You can have a different mix of financing. So one of the important things that you need to do is to figure out what the options are for financing and what types of different mixes are possible, along with the impact that would be on your interest costs and your cash flow. So here is an example. (See Figure 5)

Figure 5

FINANCING METHODS AND INTEREST COSTS

Financing Option	Interest Rate (%)	Financing Method 1 (Thousand Dollars)	2	3	4	5
Equity	--	285	85	85	--	--
PIDC	8.5	2,276	2,276	2,276	2,276	2,276
Equip. Mfg. or Power Purchaser	9.25	--	3,130	3,130	--	2,561
PMBDA	4.0	--	--	200	--	--
City of Philadelphia	8.5	--	--	--	3,415	--
Conventional	12.0	3,130	--	--	--	--
DOE grant	--	--	--	--	--	854
Total		5,691	5,691	5,691	5,691	5,691
Annual Payment		600	542	534	528	466
First Year Interest		569	501	491	483	430
First Year Principal		31	41	43	45	36

We have five different financing methods, showing the same total amount of money being financed, but different mixes and the effect on the annual payments include interest and principal repayment. In this particular case, the interest payment varies from about $430,000 a year to $570,000 a year. So you're talking about quite a significant difference depending on your ability to determine the best mix of financing.

Once we have the financing cost -- that's the big component of your cash outflow -- another component is the annual operating and maintenance cost. There might be something called a "user charge". If you don't own the dam, you will have to pay whoever owns it either a royalty or a lease payment for letting you use the dam for power generation. In our case, the Commonwealth of Pennsylvania owned the dam but Pennsylvania Hydro Development Corporation had the permit. So we were negotiating with the Commonwealth in terms of what the payment would be. We had some estimates of what might be the range of negotiated charges for the use of the dam. Then there are other expenses like insurance cost; the operating and maintenance expenses to take care of the equipment; the general and administrative expenses; depreciation and amortization costs. The range of these costs depends on the method used for depreciation and how well you are able to negotiate the "user charge".

The depreciation/amortization can be analyzed in great detail because there are different accounting methods available for the various capital cost components. So you will start off with your initial cost estimate, escalate that cost estimate over the period of time; certain portions of your civil works you might be able to depreciate over 40 years while other parts might be depreciated over shorter periods of time. And again, if I.R.S. comes in with new rules and regulations regarding depreciation schedules, you might want to take advantage of them. So this is again something that has to be calculated.

Then there's the question of the overall revenues and expenses. We have the ability to develop a pro forma income statement. Here we have shown something like seven different cases of revenues coming in primarily from energy sites. We had assumed no capacity credit. This dam is in the service territory of Philadelphia Electric Company, which has excess capacity right now. We have different escalation rates we can assume for revenues based on at what rate the energy costs are likely to increase for Philadelphia Electric. We have different financing methods which will determine the different financing costs.

We have different escalation rates on operating and maintenance costs. The results of this will give us the first year cash flows. (See Figure 6). The first year cash flow ranges from a +69 to a -246 thousand dollars. Again, the assumptions you make and the options you have for financing, for revenues, and sales will make a tremendous difference in the bottom line. This can be projected over the 30-year accounting life or 80-life cycle of the dam. You can get an income statement projected over this period.

So starting at 1982 -- perhaps it's optimistic now to assume that -- but 1982 was then our first year estimated operations, we have projected the income and expense streams over the 30 year life of the dam. (See Figure 7). As you can see, the zeroes in the top line are the capacity credits; the second line represents the revenues from the sale of electricity based on energy charges. We have assumed in this case that the energy charges were escalated at a reasonably high rate, basing the rate of energy a little bit higher than inflation. The costs were also escalated, at a little bit lower rate than the revenue escalation. As a result, the cash flow appears better and better as we go further out in the future. The cash flow has to be discounted to the present value.

Figure 6

ECONOMIC FEASIBILITY ANALYSIS - FLAT ROCK DAM

FIRST YEAR OF OPERATION (1982)

Assumption	Base Case	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
REVENUE ESCALATION	10%	10%	8%	7%	10%	10%	7%
OPER. COST ESCALATION	7%	7%	7%	7%	7%	7%	8%
POWER PURCHASER	CCA	PECO	CCA	PECO	CCA	CCA	CCA
FINANCING METHOD	3	2	3	1	3	5	3
OPERATING COSTS	Low	Low	High	High	High	High	High
			(Thousand Dollars)				
REVENUES	739	603	705	565	739	739	689
EXPENSES							
DEPR/AMORT	453	453	453	453	453	453	453
INTEREST	491	501	491	569	491	430	491
OTHER OPR. EXPENSES	136	136	211	211	211	211	220
TOTAL	1,080	1,090	1,155	1,233	1,165	1,094	1,164
NET INCOME	(341)	(487)	(450)	(668)	(426)	(355)	(475)
+ DEPR/AMORT	453	453	453	453	453	453	453
- PRINCIPAL	(43)	(41)	(43)	(31)	(43)	(43)	(43)
CASH FLOW	69	(75)	(40)	(246)	(16)	55	(65)
YR. OF FIRST POSITIVE CASH FLOW	1	3	3	11	2	1	4

Figure 7

PROJECT - FLAT ROCK DAM

INCOME STATEMENT

($1000)

INCOME		1982	1983	1984	1985	1986	1991	1996	2001	2006	2011
CAPACITY CREDITS	$	0	0	0	0	0	0	0	0	0	0
POWER SALES		734.0	792.7	856.2	924.6	998.6	1467.3	2155.9	3167.8	4654.5	6839.0
TOTAL REVENUES		734.0	792.7	856.2	924.6	998.6	1467.3	2155.9	3167.8	4654.5	6839.0
EXPENSES											
INTEREST EXPENSE		538.2	534.4	530.3	525.8	520.9	488.6	438.3	360.1	238.4	49.0
DEPRECIATION		241.7	241.7	241.7	241.7	241.7	241.7	241.7	42.1	42.1	42.1
AMORTIZATION		228.2	228.2	228.2	228.2	228.2	0.0	0.0	0.0	0.0	0.0
INSURANCE		44.0	47.5	51.3	55.4	59.9	88.0	129.2	189.9	279.0	410.0
LOCAL TAXES		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATION & MAINTENANCE		79.0	85.3	92.1	99.5	107.5	157.9	232.0	340.9	501.0	736.1
GENERAL & ADMINISTRATIVE		44.0	47.5	51.3	55.4	59.9	88.0	129.2	189.9	279.0	410.0
USER FEES		16.0	17.3	18.7	20.2	21.8	32.0	47.0	69.1	101.5	149.1
OTHER EXPENSES		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL EXPENSES		1191.0	1201.9	1213.6	1226.1	1239.7	1096.1	1217.5	1192.0	1440.9	1796.1
NET INCOME BEFORE TAX		-457.0	-409.1	-357.4	-301.5	-241.1	371.2	938.4	1975.8	3213.6	5042.8
PRINCIPAL		40.7	44.5	48.6	53.1	58.0	90.3	140.6	218.8	340.5	529.9
CASH FLOW		-27.9	16.2	63.8	115.2	170.7	522.6	1039.5	1799.1	2915.2	4555.0

*** GRC - MESH ***

One method that has been used to evaluate economics, particularly by the government, is the benefit-cost ratio. The benefit-cost ratio is defined as the discounted value of the net revenues; that is, the revenues minus the operating expenses, divided by the initial investment. In this particular case, under the particular assumptions that we are using, the benefit-cost ratio is 1.68. Now, benefit-cost ratio is a term that is generally used in the public sector analysis. If you go to the bank, they probably wouldn't want to see your benefit-cost ratio; they may want to see the internal rate of return or present value of discounted cash flow. And this is very easy to do in this kind of analysis because we have it programmed so that you can very quickly calculate all of these different measures of financial viability of the project.

In summary, starting off at the beginning with the engineering design of the project, we have carried through the initial capital cost, the escalation, the various financing methods, various marketing strategies, revenues, costs, and so on. Finally we arrive at the bottom line which could be the benefit-cost ratio, the internal rate of return, or a number of other measures of financial performance. For example, a municipality may have to look at something like the debt coverage ratio rather than a benefit-cost ratio or discounted cash flow. The advantage of using this framework is that some of these things can be determined very quickly. The final result of this analysis was a series of different cases, but we had something called a base case which included a 3.5 megawatt design, and this is a summary of that base case. (See Figure 8)

Figure 8

HIGHLIGHTS OF FLAT ROCK DAM

FEASIBILITY STUDY

MAX. OUTPUT - 3.5 MW

TYPE OF TURBINES - TWO 3000 MM TUBE TURBINES

POWER OUTPUT - AVG. YEAR - 18 MILLION kWh

HEAD - 17 TO 20 FT.

MEAN STREAMFLOW - 2691 CFS.

CONSTRUCTION COSTS - $4.4 MILLION

ESCALATION AND AFDC, ETC. - $1.3 MILLION

TOTAL FUNDS REQUIRED - $5.7 MILLION

INITIAL OPERATION - JAN. 1982

BASELINE FINANCING PACKAGE

- $0.2 MILLION PMBDA AT 4% INTEREST
- $2.5 MILLION PIDC AT 8.5% INTEREST
- $3.0 MILLION EQUIP. MFG. AT 9.25% INTEREST

ANNUAL PAYMENT (30 YR. MTG.) - $542,000

POWER MARKETING -	Option 1 PECO	Option 2 CONT. CORP.
Current Rate (Mid '79)	26.0	32.5
Escalated Rate - 1/82	33.0	41.2
Power Sales (Million kWh)	18.0	18.0
Revenues (Thousand $)	603	739

FIRST YEAR EXPENSES (Thousand $)		
Interest	491	491
Depreciation, Amortization	453	453
O & M, etc.	136	136
Total	1080	1080
NET INCOME	(477)	(341)
CASH FLOW	(67)	69

The base case had the first year cash flows which were negative assuming sales to Philadelphia Electric Company. (We were at that time also looking at an option of possibly selling the electricity to a private industrial firm). Selling to Philadelphia Electric had a negative cash flow in the first year but a positive cash flow in the second year and thereafter. Under the assumptions that we had made for energy sales, the economics of the project would have been reasonably favorable with a benefit-cost ratio of 1.68.

I've tried to run through this rather rapidly since we are running behind schedule a little bit, and as I said, the handout that you'll receive will have more detail on this methodology. At this point I'd be glad to answer any questions that you may have on the approach.

Q. What was the annual return and capacity?

A. The net power was about 18 million kilowatt hours per year. About half a million dollars revenues in the frst year from energy sales and three-and-a-half megawatts capacity.

Q. Did you use an avoided cost rate?

A. We talked to Philadelphia Electric Company (PECO) and they gave us the P.J.M. running rate. It was the average incremental monthly charge that Philadelphia Electric paid to P.J.M. during the previous month.

Q. How was the future rate determined?

A. We're using an annual escalation rate. We used the PECO rate and escalated that at whatever the escalation assumptions were for 1982, and then escalated beyond that.

Q. Did you use only the one method?

A. That was only one method. Now, we could define this in terms of actually looking at the time of day rates and so on. It can very easily be done in this kind of analysis. But this was two years ago, and we had no idea whether the rates being paid would be on the basis of time of day or not, and whether we could match the time of day rates against the river flow, and so on.

Q. How was your monthly capacity rate determined?

A. We can do that, but did not for Flat Rock. For some other projects we have run monthly flow duration curves and are able to produce monthly energy output, and then we can compare that against monthly rates.

Q. Why didn't you estimate capacity credits for the project?

A. Well, we're being very conservative. P.E. was not willing to offer capacity credits. In any case, about 10 years out you're doing so well that the capacity may not make a great difference. But again, this is illustrative of what you can do. At this point it would be very hard to project, short of using a capacity expansion model for P.E., what the capacity credit should be.

At Blacksburg, Virginia, Mr. Thomas C. Hough, Manager of Hydropower Studies for SRC, updated the presentation delivered in Harrisburg, Pennsylvania by the following:

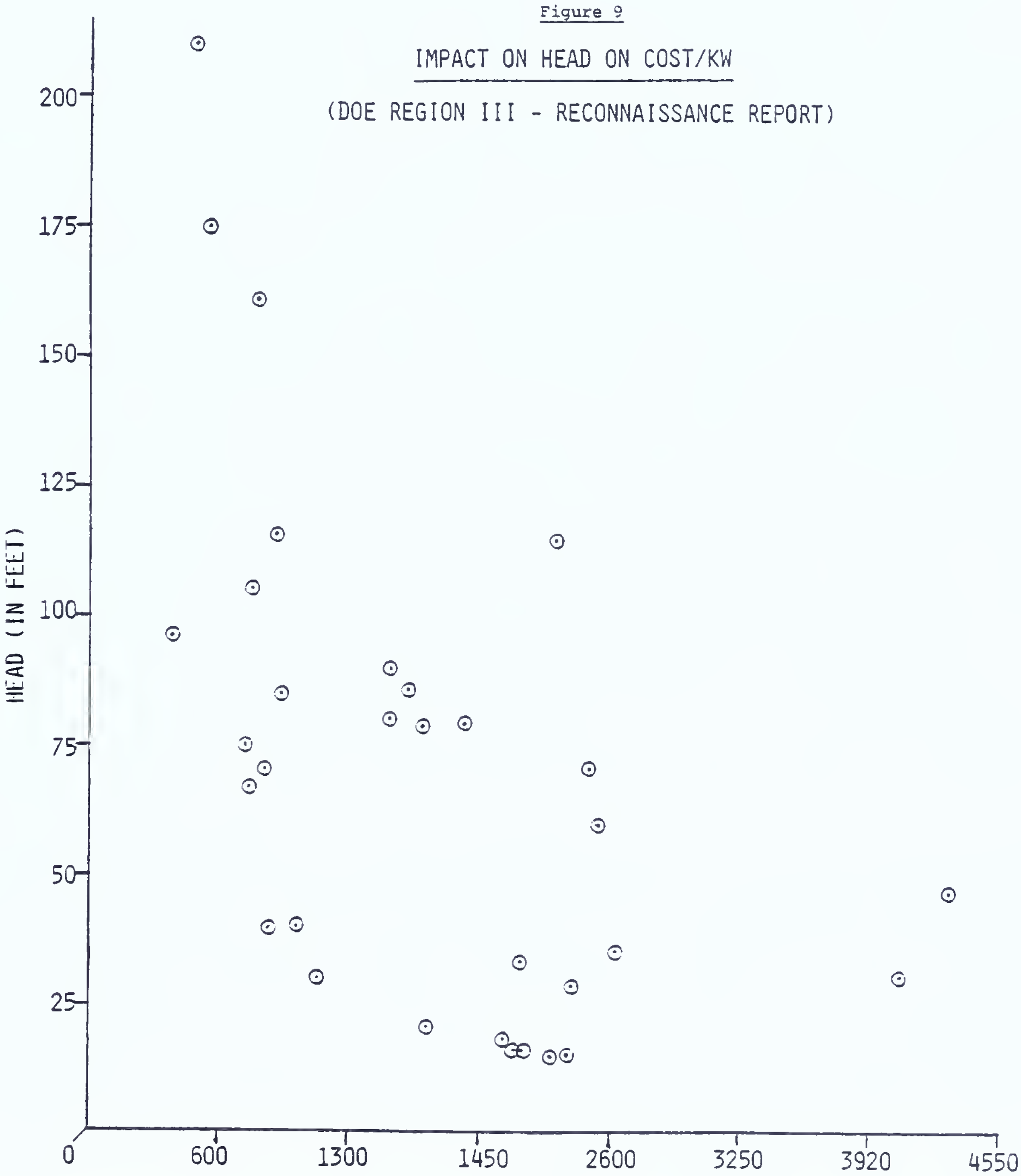
DOE Region III site reconnaissance studies sponsored by DOE have provided a great deal of data on potential hydro projects. I have analyzed this data and will be presenting two slides which confirm some of our basic assumptions about the relationship of site characteristics and costs.

This first slide shows the relationship of head in feet to the cost per kilowatt of installed capacity. As expected, and as pointed out by one of the previous speakers, the high head projects do have low costs per kilowat, but so do some projects with medium heads and low heads. The figure shows that the range in cost per kilowatt is greatest in low head projects. Low head costs range from $800/KW to over $4000. Medium head projects have less variation than low head but more than high head projects. (See Figure 9)

Figure 9

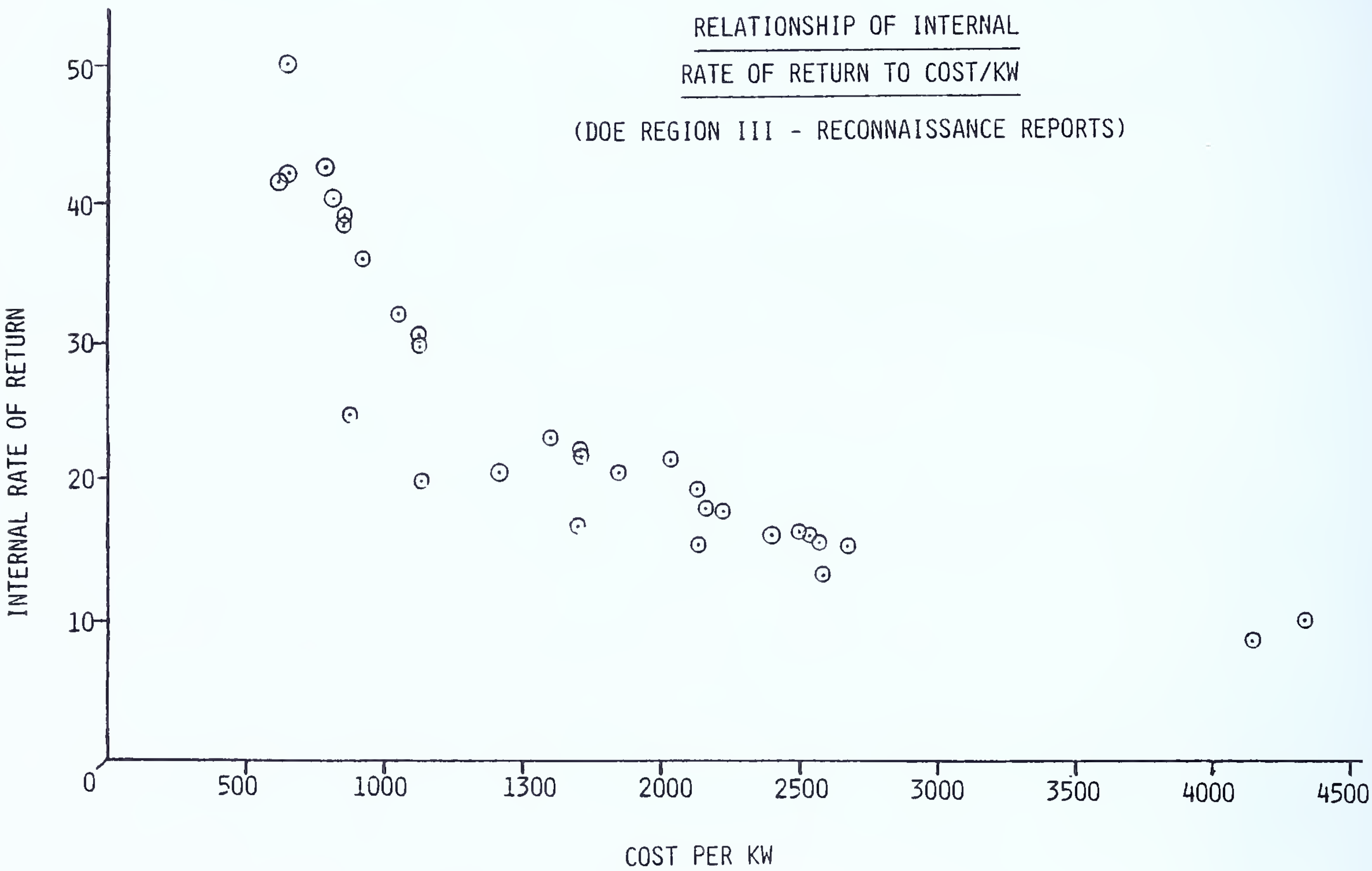
IMPACT ON HEAD ON COST/KW

(DOE REGION III - RECONNAISSANCE REPORT)



The second figure is also based on Region III data. (See Figure 10) This figure presents the relationship between cost/kilowatt and internal rate of return. Obviously, we expect a close relationship between these two statistics since cost is a common component of each. There are two ways to use the data in this figure. If your project can be brought on line for less than $2000 per kilowatt, it would probably produce returns that are attractive for private development. If costs are above $2000/kilowatt some projects would only be attractive to public entities. The next two speakers on private and public finance will be able to provide more details on the level of returns required.

Figure 10



The second way of viewing this figure is to use it to see if hydropower as a generic investment provides opportunities for return that are large enough to attract investment. Clearly, there are some very attractive projects in our region. I am convinced that these projects will attract capital and be developed. I am also convinced that other "good" projects will be identified that will provide competitive returns. However, I believe that there is a limited window for hydropower and the competition for the highest avoided costs will come from cogeneration and other qualified facilities. Even though hydro economics will improve as fuel costs rise, other sources of electric potential will also be developed.

PUBLIC FINANCING-MUNICIPAL FINANCING & OWNERSHIP OPTIONS

Kathryn W. Donahue
Senior Vice President
Public Financial Management, Inc.

Mrs. Donahue is a 1969 graduate of Rosemont College (BA) and a 1972 graduate of the Wharton School, University of Pennsylvania (MBA - Finance). She has served as Senior Vice President of Public Financial Management, Inc. since 1980.

Prior to accepting this position she served on the City of Philadelphia Planning Commission; supervised analysis of taxation patterns as Director of the Economic and Taxation Committee for the Philadelphia Chamber of Commerce; managed both as agent and participant in project finance and commercial lending activities in natural gas, electric utilities and special situation financings of world-wide responsibility as Vice President of the Energy Lending Group, First Pennsylvania Bank, N.A.

Mrs. Donahue is financial advisor in areas of public utility debt issuance, hydro-electric power issues, other energy-related matters, especially synfuels, oil and gas regulatory matters, economic and industrial development, and seaport revenue bond fields.

Good morning. I think we had passed out to each aisle a handout which will be used as we proceed with this topic. I'm going to discuss municipal finance and how that relates to hydro-electric power or small scale hydro. I think that the first thing to remember is that ten to fifteen years ago, hospital financing was in about the same state that hydro-electric financing is today. Hospital financings were originally achieved through the general credit of a municipality, or through very strong contractual arrangements.

After the market became familiar with the third party payment system, which is essentially the Blue Cross-Blue Shield mechanism that is used in hospital financings as the security vehicle, those financings became quite prevalent. Until that time, the activities of the hospitals had to have very major debt service reserves, very major coverage reserves. This financing mechanism took a long time to get established.

I think there is hope, I think that within ten years we will definitely see an established method of financing hydro projects without substantial recourse to municipalities or to private financing companies. I think today, though, it is generally accepted that you must have either a strong contractual arrangement with a municipality or the faith in credit of the municipality behind it, before we consider the economics of the project. I hope that will not continue to be true, and I believe that the process is getting more established.

Let me say first that if you are a municipality, especially in this District 3, you know the problems of trying to finance all of the critical expenditures that you face as a city or municipality; you must keep your streets clean, and protect your citizenry. Therefore, a hydro-electric project, even though it would be a valuable project for your citizenry, is a project that would be considered an elective project, rather than a required project. The first thing you should consider as a municipality is some sort of a debt policy review. Determine what your capital expenditures are over the next decade. Determine your tax base, and your revenue stream, how are they? After you've gone through that analysis, you'll be in a position to assess that typical contradictory problem that any elected official or municipal official has; that is you'll be able to determine whether or not you can afford to finance the project on your own.

As you check the handout, and I apologize for not having made enough, I think the DOE is to be congratulated at the attendance today. You'll see that the typical method of financing of a project of this sort, to date, would either be through the operating revenues of a municipality, or the first picture (figure 1) in the handout, a G.O. Bond. Under a General Obligation Bond, as I'm sure you know, the full faith in credit of a municipality is behind the debt, and it is the tax base or the revenue base of the city or municipality that is supporting the debt.

The second form of financing used today would be a revenue bond financing. And, under the revenue bond financing mechanism, which is quite similar to a General Obligation Bond, although you are looking primarily to the revenue stream from the hydro project to finance it. Whereas in this graph, (figure 2) it shows the financing done through the subdivision or the municipality, you could assume perhaps, that an authority that would be established by a municipality might do the financing with some sort of a guarantee by the City. The best that you could probably achieve in getting financed, unfortunately, would be some sort of a guarantee release. By that I mean, there have been many parking authorities that have been financed, where after they've had four or five years to determine the revenue stream, the municipality's guarantee can be released. That, I think, would be a probable mechanism for financing a hydro-electric project. The problem, as you all know, is that at the front end, there are just not sufficient revenues to cover the debt service that may be required and the other costs involved, whether you use tax exempt, or taxable financing.

You've done some assessment for your city or your municipality as to the amount of debt you can assume. You've determined that you can't assume further revenue bond debt, nor can you assume further general obligation debt because you are concerned about your rating, also you're concerned about the critical projects that you face. In that regard, you may try to consider a less visable role, and that less visable role can take the place, as I'm sure you know, of purchasing the power that would be produced by an independent operator to whom you might lease a site, or to whom you might offer a site on which you have the priority permit. Under this type of

a mechanism, you can consider taking a royalty, or you could consider taking a net project revenue participation. If it looks to you as if the economics of the project are good, you probably would opt for the latter, which would be a project profit participation route. That in a sense, the project gets more and more economic in time, you'll have more chance to participate. Unless you can get an escalating royalty.

Obviously your consideration about going forward as a municipality, either as a lessor or a contractual acceptor of the power, will relate to your assessment of how strong that project is. I think the presentation just before this one showed you a pretty good idea of all the things that go into a typical project analysis and we feel strongly as financial advisors, that you're going to want to see a project that is economically sound. You're going to want to know how much exposure you can look at, if you're going to sign a take-or-pay, or hell-or-high-water contract. These are the vehicles which would allow a project financing, whether it be done through a tax-exempt authority, or an authority which could issue a tax exempt debt, or whether it would be done through a taxable financing entity. So you're going to want to do some strong analysis of the project itself, is the point I'm trying to make. You're going to try to see what sort of contingent liability you could be accepting if you sign a strong take-or-pay contract.

There have been some municipal financings, particularly on the West Coast, where the avoided costs may be higher, or where the Utility Commission treatment is such that the certain cities have signed contractual arrangements with issuing entities, with an authority or private operator and have gotten tax-exempt financing on the strength of that take-or-pay contract.

Let me say that I've talked about tax exempt and taxable financing and everybody asks, "Which is less expensive?; Which is more expensive?; How can I be sure that I would issue a tax-exempt debt?" Everybody also is hoping to achieve eventually that nirvana of financing which would be a tax-exempt debt, and the ability to take tax credits, ITC and deductions. That's pretty fancy, and that's going to take some time and money. But we do believe that over time that can be done. I think that we've shown here a couple other alternatives. Let me say that most of the runs that I've seen show that at a 50% tax bracket, taxable financing mechanisms for projects of this sort, with the heavy investment tax credit capability, energy tax credit capability, and the deductible interests and other costs involved, the taxable mechanism is probably less expensive than most tax-exempt debt today. However, that does not mean that if you are a municipal entity, while trying to go forward with a hydro project, that you should hold off and wait for taxable financing, or try to get this thing done in a taxable manner, because as you all know, it seems an awful long time from the decision to go forward with the project until the actual financing, and there have been very few, if any, taxable financing mechanisms set up with partnerships, or where the tax benefits can flow to the corporate owner.

In any event, we show several drawings here, we can skip past the joint action agency and come back to that, I think that's figure 3. Figures four, five and six show leverage leasing transactions, partnership transactions, or industrial development bond transactions. All of these are pretty graphs, and let me say that particularly for the first one, leverage leasing, was particularly complicated to get done. There have been so far, very few, if any, leverage lease transactions accomplished with utility related projects. There was a Gulf States utilities project completed in Texas with a $400 million leverage lease for a coal facility. There have also been individual pieces of equipment involved with various projects that have been leverage leased. However, for a municipality to enter into a leverage lease would require that the municipality sign very strong take-or-pay contractual arrangements, and in the other drawings you'll see that as well, for a private partnership, the concept is the same. Probably, unless you have an industrial user or utility in that area, where you can get good long term contracts, the likely end user is going to be the municipality itself. Therefore, you're going to have to accept some form of contingent liability, if you are a municipality. I believe this may change over time, and I hope that it will, through a strong long term contract with a utility or through a strong industrial contract. However today, you're probably going to have to accept some liability as a municipality in order to finance a project.

One thing to consider as you look at taxable versus tax-exempt debt issuance and go through the cost ramifications of it, is to determine that your project is public purpose. Public purpose is important from the standpoint of the IRS, and also important from the standpoint of the state regulations controlling the issuance of tax-exempt debt within that state. In the Commonwealth of Pennsylvania, there have been various pieces of legislation proposed which would say that hydro projects are tax-exempt, that they are public purpose. That legislation has not yet been passed. I'm laughing here because I'm thinking that I've worked a lot with Philadelphia lawyers and they tend to be very conservative, but I want to let you know that as they look at the market today for hydro projects, they hedge their response, but they answer the question "Yes, we think that it would be tax exempt if the city or municipality issued bonds to finance a hydro project; where in some manner then end user could be shown to be either the municipality, or the power would be sold to a public utility. If the power is sold to an industrial user, or to an industrial user only, you may have a problem with the issuance of a tax-exempt debt". If its a major piece of the power that they're purchasing, you may have a similar problem.

As I had indicated, there is legislation in Pennsylvania now and there has already been legislation passed in Virginia, which indicates that this financing is public purpose. An authority has been set up in Virginia, unfunded as yet unfortunately, to finance hydro projects and other synthetic fuel projects. If you're a municipality looking to get into this field, and I do believe that over time you would be very glad, as would your citizenry, that you had made that investment.

You must carefully assess how the power is going to be used, you must further carefully assess whether you want it to be tax-exempt or taxable debt. If you see that it's going to be a taxable debt issue, consider one of the drawings that's in here, consider a partnership arrangement, perhaps.

That is an allowed activity for a municipality in the Commonwealth, the lawyers believe, that might be a way for you to take advantage of the issuance of tax-exempt debt, and also to have someone else take advantage of the rather material tax benefits. In any event, we wish you luck, and I do believe that hydropower eventually will be an economic development for all the municipalities in Pennsylvania and the other states in District 3.

Any questions? Yes. (1) "How long would you estimate the approval for industrial bonding will be?" The typical procedure is to have an approval done by a county or an industrial development authority and that can take as short a period of time as 30 days for the actual approval. Of those industrial development bonds that I've participated in, the normal lead time has been about 3 to 4 months. Usually that is going in with complete information in hand, or a good bit of information in hand, including the typical project finance criteria: The cost, the revenue streams, the end user, the contractual arrangements pretty much in place. So I think it could take about a year if you haven't got all the pieces in place.

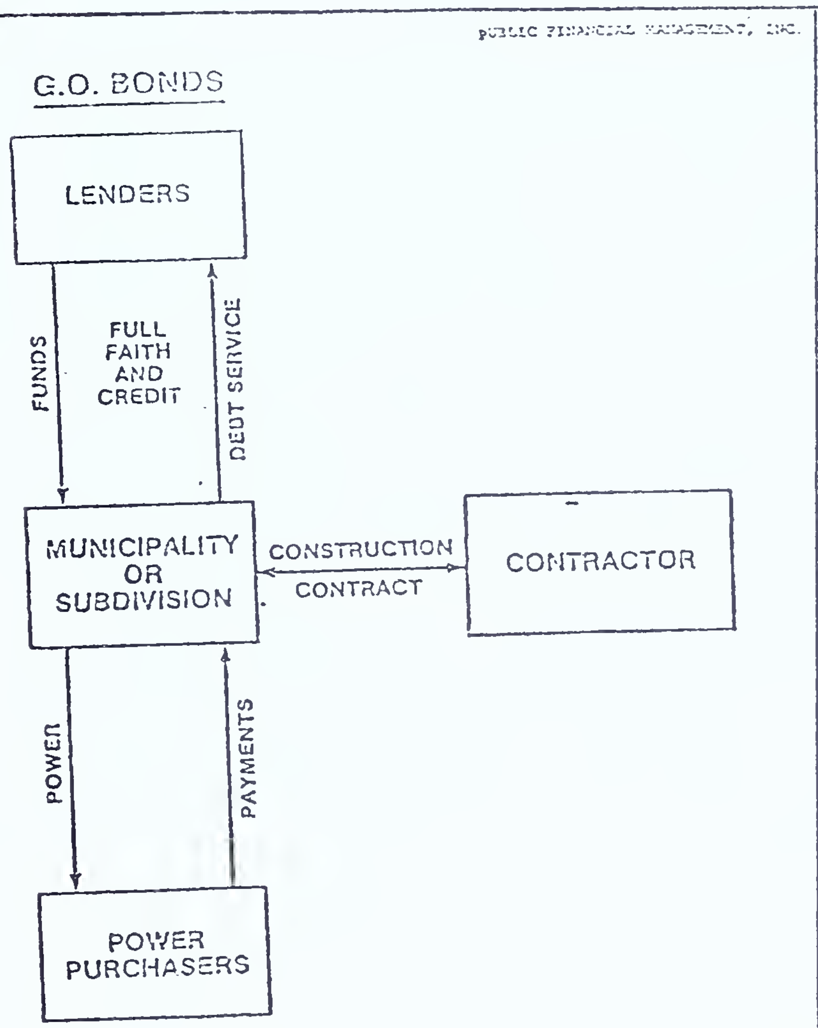


Figure 1

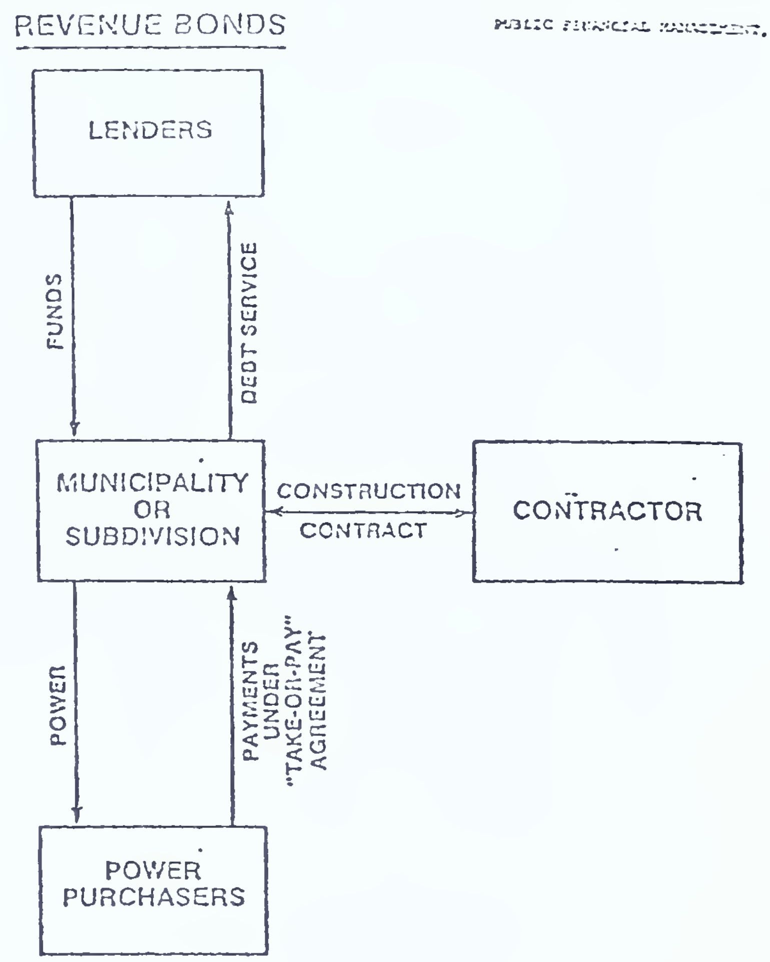


Figure 2

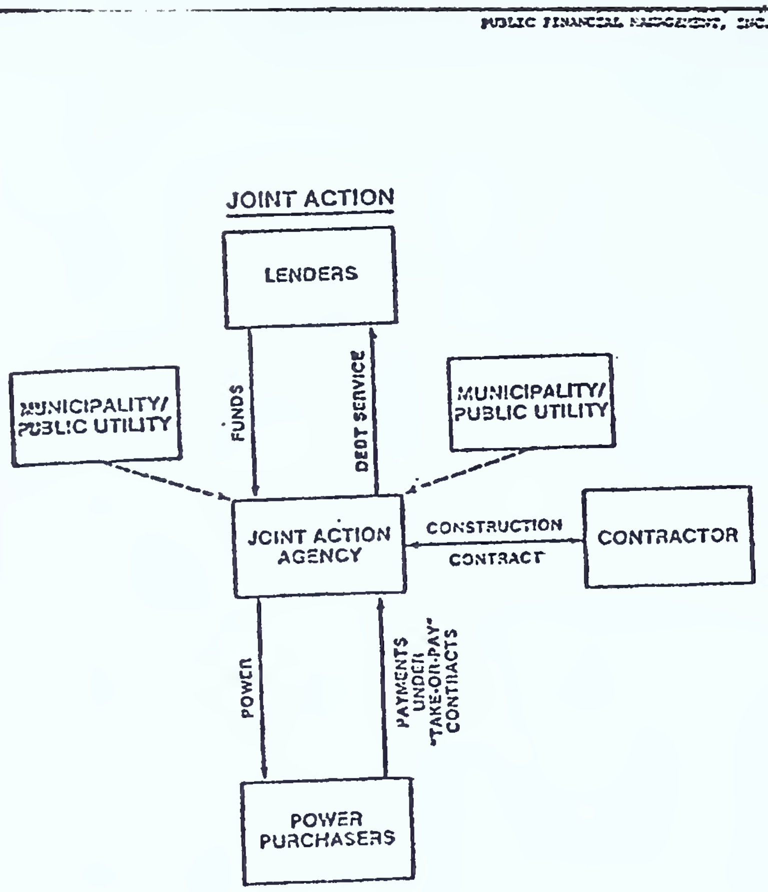


Figure 3

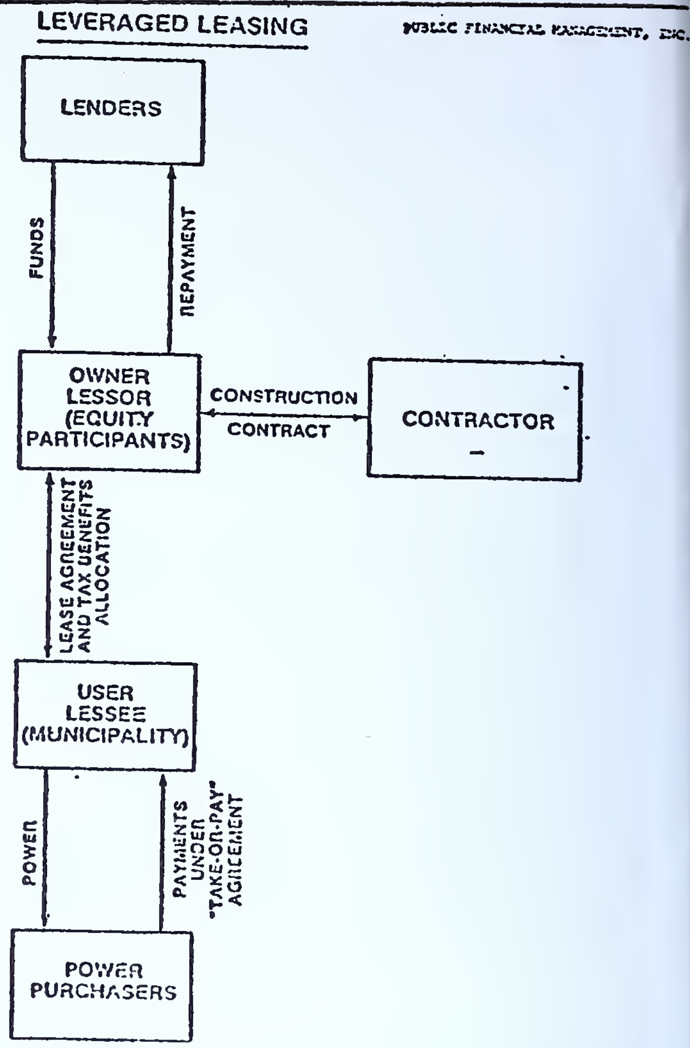


Figure 4

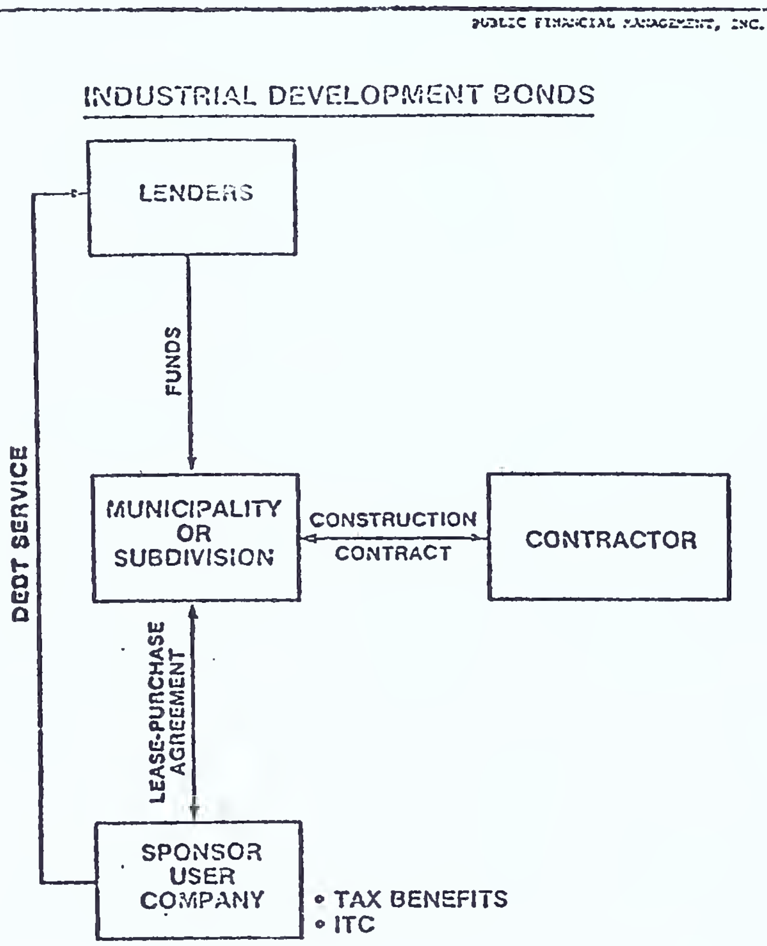


Figure 5

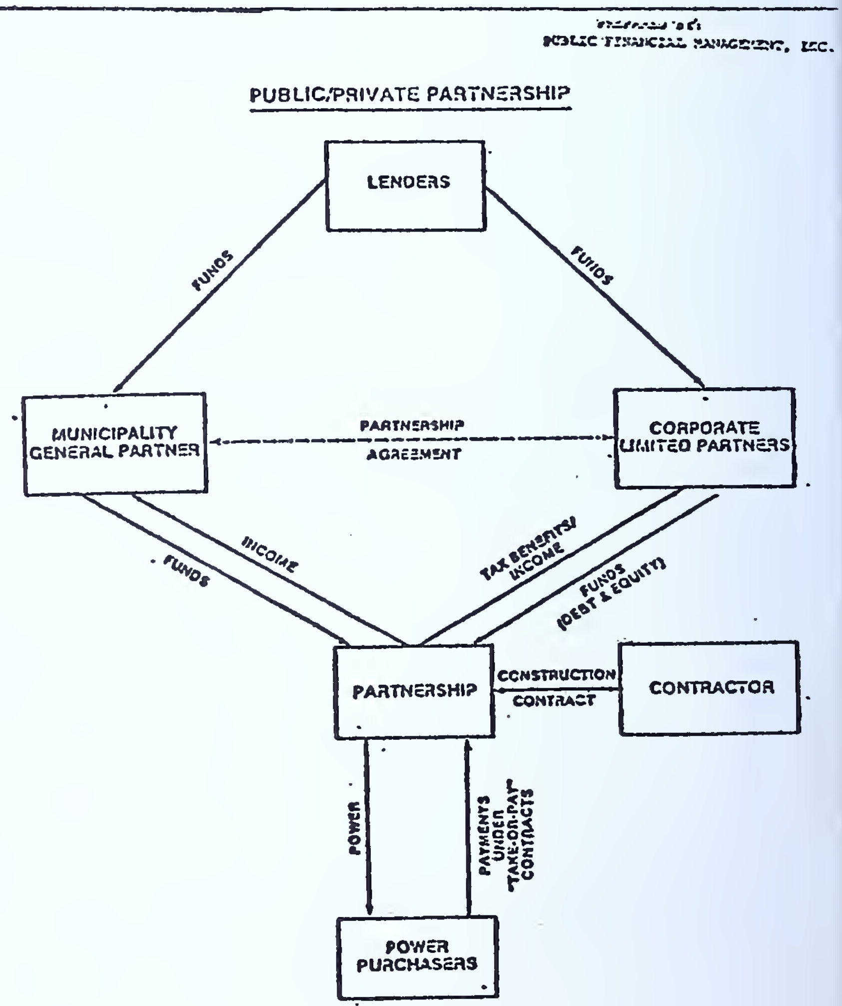


Figure 6

PRIVATE FINANCING - OPTIONS, EQUITY, TAX BENEFITS AND LONG-TERM DEBT

Robert Cooper
as delivered in Harrisburg, Pennsylvania, May 13, 1981

Mr. Cooper is a graduate of the Columbia University Graduate School of Business Administration (MBA - Finance). Presently he is serving as the assistant Vice President of the Municipal Finance Department of Drexel Burnham Lambert Incorporated in their New York office.

His present activities in the investment banking business deal primarily with finance, money financial matters, international management and liaison with the foreign exchange. Mr. Cooper, together with Mr. Joel R. Mesznik (First Vice President and Manager of the Municipal Finance Department), has served in all areas of health care finance including taxable and tax-exempt financings, private placements, collateralized issues and debt restructuring.

Mr. Joel Mesznik was detained in court for the Harrisburg workshop; however, he made the presentation at VPI-SU on May 29, 1981.

With the change of administration in Washington and the coincident trend toward fiscal conservatism, as well as the Federal Reserve's increased monetary vigor, private financing of hydro development in 1981 has become an increasingly complex and difficult objective to attain. In 1980, Congress created substantial incentives to the development of hydroelectric facilities with the passage of the Windfall Profits Tax Act. However, in 1981, Congress is threatening to take away other incentives to hydroelectric development by threatening to remove or prohibit industrial development bond financing of commercial projects.

Over the past couple of years, the Federal government has established many grant loan and loan guarantee programs, including the PURPA, Title IV loan program and the programs of the Farmers Home Administration, the Department of Housing and Urban Development, and the Small Business Administration. However, due to the budget cuts presently being considered by the administration, these programs stand a good chance of being cut back significantly or eliminated altogether. Finally, with regard to general market conditions, the Federal Reserve's increasing emphasis on the monetary aggregates as opposed to money market interest rates as the means of implementing the nation's monetary policy, has resulted in unprecedented gyrations in interest rates. Presently interest rates are at or near their historical highs. Financing hydroelectric development for private developers in 1981 is going to be a difficult prospect.

With that background I'd like to pursue two financial alternatives available to private developers which I've categorized as being either conventional financing -- by that I mean taxable debt and equity financing, or tax-exempt financing using industrial development bonds.

On the conventional side, the traditional lenders of money at taxable rates have been the commercial banks, life insurance companies, and pension funds. Of the three, the life insurance companies are today the only viable source of long-term, fixed-rate money available. The pension funds, due to their fiduciary responsibilities to contributors, are restricted to buying investment-grade paper; with such paper you must have a rating and, typically, the project financed is not a startup facility. The commercial banks, although historically lenders of fixed-rate money for up to ten years, as a result of recent gyrations in interest rates are now limiting their activities. In 1980 the prime interest rate between its high and its low moved almost 10%. Given that, about 80% of a typical hydroelectric project's revenues are devoted to payment of principal and interest on debt. That kind of gyration in the prime, if you've got a variable rate loan, will make determination of economic feasibility almost impossible.

Finally, the life insurance companies have traditionally been a viable source of long-term, fixed-rate money. Unfortunately, their portfolios of fixed-rate loans have been ravaged by inflation. The life insurance companies have taken a beating to the tune of billions of dollars on their fixed-rate portfolios. And as a result are doing two things: one, they're shortening the average lives of their loans to about 15 years; and, two, they're looking for an inflation hedge in terms of an equity participation in a project.

To compete today in the long-term taxable market, it should be noted that long-term Treasury securities are currently yielding in excess of 14%, and triple-A rated telephone bonds are yielding an excess of 16%. To compete with those rates, developers of hydroelectric projects would have to expect to pay 18% or more for their money if it is strictly a loan from an insurance company. Furthermore, the average life of the loan will be between 10 and 15 years because of the effects of inflation that the life insurance companies have experienced. The solution to this problem -- and a means of mitigating the effect of these rates on your hydroelectric project -- is to enter into an agreement with the life insurance company, whereby he is allowed to participate in your project on an equity basis. In other words, he gets an override on your net profit.

If I could run through a typical scenario to exhibit how this type of financing arrangement works, as a developer, the first thing that you'd have to do would be go out and find a suitable site. You locate a site and you probably perform a quick-and-dirty feasibility study, pursuant to techniques that are readily available and are published in a variety of trade publications. The result of that quick-and-dirty feasibility study would allow you to make a "go" or "no-go" decision regarding further development of the site. If it's a "go" decision, you'd probably want to gain control of the site through interim preliminary permitting process. Once you've got your preliminary permit, you'd then be in a position to incur expenses to do a fullblown feasibility study, probably in two stages -- a preliminary study and then a final feasibility study -- to minimize your cost in the event the preliminary study doesn't look feasible. It's important at this point to get a recognized firm to do that feasibility study for you because your long-term lender is probably not going to have experience in hydroelectric development and is going to look to the name of that feasibility consultant for comfort that

the project is actually going to fly. It's also important to get input from a financial institution with constant contact with the market so that your feasibility consultant, who doesn't have that direct contact, doesn't assume interest rates that are unworkable in the present market. Once you've done your feasibility study, you can then go through the licensing process.

Following these steps, from identification of the site through the feasibility study and licensing, could cost on the order of $200,000 which is purely risk capital since you don't control the site. Since you don't have a license, you're probably not going to be able to arrange a loan from a commercial bank or from any lender unless, as a developer, you are of sufficient financial strength to be able to guarantee repayment of the loan. Many developers are not in that situation.

A way for those developers who do not have the financial strength to guarantee a loan for the preliminary work to get the up-front money as well as significant monies for actual construction of the facility, would be to form either a limited partnership or Subchapter S corporation. For a typically developed private project between 20% to 30% of the project cost should be raised in the form of equity. For a 20-million-dollar project that would mean you'd have to raise between 4- to 6-million dollars in equity initially. The incentives to equity contributors for participating in limited partnership or Subchapter S corporation are principally twofold: one, there would be tax benefits of ownership; and, two, there is the up-side potential for taxable revenue over the long term of the project. The tax benefits of ownership are basically your 10 percent investment tax credit, 11 percent energy tax credit and depreciation.

The equity that has to be raised actually isn't so difficult to raise as it might sound, due to the tax benefits. On a $20,000,000 project, if you've got 21% in tax credits, that means you've got $4,000,000 right up front that's going to be paid back to the equity participants at the time the project is built. The remaining $1,000,000-$2,000,000 of equity is really all that's at risk, and that will be paid back very shortly through depreciation. So actually raising the equity is not the most difficult part of financing the partnership. The most difficult part is arranging for a long-term lender.

In creating a partnership or a Subchapter S corporation, it should be remembered that tax credits are equally attractive to all classes of investors, whether they be corporate investors or an individual investor; to both parties the tax credits are a direct dollar-to-dollar offset of their tax liability. The depreciation tax benefits, on the other hand, are most attractive to individuals who may be in the 70% unearned income tax bracket, as opposed to a corporation that may be paying 30% to 40% in income tax.

Once you've gotten your partnership created, you've performed your preliminary and final feasibility studies and you've got your license, the next step is to arrange for an institutional lender. Hopefully, long-term at a fixed rate. This is by far the most difficult step in the process of developing a facility in that whereas hydroelectric development makes a tremendous amount of sense in the long run, as you are able to sell power at increasing rates, these projects have difficulty showing coverage in the early years; there's generally

a blind spot, particularly with rates as high as they are today and with the prices at which you can sell power today. As a result, if you approach insurance companies with the proposal, "Would you buy our debt and our debt only," they aren't going to be looking at the long-term prospects for your project. They don't stand to benefit from the tremendous increase in revenues that you expect to experience. Instead, they're going to be looking at the first five years or so when you have difficulty obtaining coverage. That is what is going to be of greatest concern to them. The way to get that insurance company to help you out by (1) lowering the interest cost on your debt and by (2) helping you out with that blind spot by allowing you to defer principal and interest on the debt, is by allowing him a participation in your project. Say for example, in return for a 5% override on your net profit you are able to negotiate him down from 18% to 14% on your loan. Say the loan is 15 years; offer him participation out to 20 years. That might help him to reduce the interest rate on the loan even further. The other concession that the insurance companies can make is, of course, helping you out with the blind spot by allowing you to defer principal and interest on the loan.

In addition to the inflation hedge, life insurance companies will be looking for debt service coverage. They're going to want a coverage factor of at least 1.2 to 1 on debt service. They will also want reserves for dry seasons, which reserves probably will amount to 15% of your bond issue and can be funded either out of equity -- developers can get a commercial bank to put up a Letter of Credit on their behalf to fund the reserve so that they wouldn't actually have to fund it with cash -- or it can be funded through project revenues as the project begins to operate.

Also, if you're going to approach a life insurance company with the proposal that they be allowed to participate in your project, don't rush into tying up a long-term take-or-pay contract. Although it's safer, it limits the upside potential. Surprisingly, many life insurance companies are very sophisticated about where energy prices are going and are willing to take the risk of not having long-term contracts in return for the upside potential.

One instance in which a contract might be appropriate, however, is where your economic feasibility doesn't work. You've arranged with a life insurance company to participate in the project; they've reduced the interest rate from 18% to 14%; they've tried to cover your blind spot, but still you need 10¢ per kilowatt hour and the going spot rate is only 8¢ per kilowatt hour. In this type of a situation, an intermediate term contract, whereby the utility will pay you your 10¢ per kilowatt past the crossover point when his avoided cost exceeds 10¢ per kilowatt hour, is the only time he is paying 10¢ per kilowatt hour rather than 8¢ at which he could buy the power elsewhere, the 2% difference accrues as a loan against you. At the crossover point, where his avoided cost begins to exceed 10¢ per kilowatt hour, he continues to pay you 10¢ per kilowatt hour until you've repaid the loan that accrued in the early years. Once you've repaid the loan, the contract becomes void and you begin selling power at the avoided cost.

Finally, another important factor which life insurance companies are going to look at is the construction contract. Your contract should contain a guaranteed maximum price rather than cost-plus. It should provide for penalty payments, and there should be full performance and completion bonds for completion of construction.

Having gotten conventional financing out of the way, I'd like to take a quick look at tax-exempt financing. Basically, there are three provisions of Section 103 of the Internal Revenue Code which permit private sector developers to finance hydroelectric projects with tax-exempt bonds. I'll mention them briefly. The first is the $10,000,000 "small issue" limitation which, simplistically, allows you to issue industrial development bonds up to $10,000,000 to finance hydroelectric projects. The second is the local furnishing provision of the Code which, in effect, says that provided the financed facilities are part of a system serving at most a two contiguous county area or alternatively a municipality and one contiguous county, and provided also that the output of the facility is made generally available to the general public upon reasonable demand, private sector developers can finance with industrial development bonds without regard to the principal amount of bonds issued. With the "local furnishing" provision you are not subject to a $10,000,000 limitation; however, you are subject to selling the power within a two contiguous county area, which is very complex and often difficult to comply with. The third provision of the Code, which is newly amended pursuant to the Windfall Profits Tax Act, is a provision which permits tax-exempt financing of "qualified hydroelectric facilities". Basically, this provision of the Code allows you to finance up to 125 megawatts at varying percentages of tax-exempt versus taxable debt, providing the facility is owned by a public body. If pursued by a private developer, his position eliminates all the tax benefits of ownership because, since you can't own the project, you can't take any of the tax credits and you can't depreciate the property. Finally, the Code permits tax-exempt financing of "facilities for the furnishing of water". It may be that erection of a dam which is a multiple-purpose dam would qualify as a facility for the furnishing of water.

The benefits of tax-exempt financing, of course, relate principally to the interest rate. Tax-exempt financing presently would allow you to reduce the interest rate by about 5%. Another benefit is that by doing tax-exempt financing you can be the beneficiary of a certain amount of arbitrage income -- arbitrage off the capitalized interest fund, a debt service reserve fund, and your construction fund. What I mean by arbitrage is that if you finance at 12% and you can turn around and temporarily invest those funds before you use them at 16%, you make a 4% spread which further assists in reducing the cost of the project. The disadvantage of tax-exempt financing, of course, is that you lose, if you finance under the qualified hydro facilities provisions of the Code, all your tax benefits. In any event, when you finance with tax-exempt bonds you're going to lose at a minimum the energy tax credit. So the best you can do is a 10% investment tax credit and depreciation.

If you were to pursue tax-exempt financing in this market, a private placement of the bonds would be very difficult. The traditional buyers of tax-exempt bonds have been commercial banks, casualty rather than life insurance companies, bond funds, and individuals. Commercial banks are presently not in the need of tax-exempt income and are out of the market. About half of the traditional casualty companies are out of the market, and those that are buying are buying very very selectively. They're seeing a lot of very high quality paper and just are not buying privates unless it's very high quality. What you're going to be left with is a public offering for which you probably need a rating; in order to get that rating you'll probably have to enter into a long-term take-or-pay contract with an "A" or better rated utility or municipality which limits your upside potential.

Finally, the creation of a partnership to provide some of that upfront money as well as construction funds, although doable with tax-exempt financing, is limited because the tax benefits are limited. The energy tax credit is gone. If you were to finance another under the qualified hydro facility provision, you will be prohibited from owning the project so you wouldn't be able to create a partnership at all. Essentially, tax-exempt financing involves a trade-off: lower interest rate and arbitrage earnings versus the tax benefits. It's not all that clear which is the better mechanism, which is cheaper. It will be determined by the circumstances of the individual developer and will require quite a bit of financial analysis to see which, in fact, is the best in the long term.

UTILITY CONTRACTS
WITH
LOW HEAD HYDRO INSTALLATIONS

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Mr. Rodisch is a 1950 graduate of Drexel University (BS - Electrical Engineering) and is a Registered Professional Engineer in the Commonwealth of Pennsylvania.

His career, primarily with the Philadelphia Electric Company, has been varied with the major portion of his time devoted to business services of this municipal utility. This liaison with the public and business world has led to his new assignment.

Recently he has been given the supervisory role of the newly created Alternate Sources Section. This new challenge includes responsibilities for installation, contracting and developing of solar projects, cogeneration, electrical vehicle programs and other alternate sources. Hydroelectric power or the use of a renewable resource is among his new energy assignments.

INTRODUCTION

Perhaps the best way to introduce the particular manner in which Philadelphia Electric Company and its subsidiary, the Conowingo Power Company, conduct negotiations with a low head hydro developer is to describe an actual case where the water turbine is in operation.

Over two years ago the Pennsylvania Public Utility Commission sponsored a seminar on low head hydro at Carlisle, Pennsylvania. At that meeting I had the opportunity to meet Mr. Paul Shirk. We discussed his intention to install a water powered generator at his property in North East, Maryland which is located in the service area of the Conowingo Power Company. We had on hand at that time copies of our requirements for operation of private generation at secondary voltages. I supplied him a copy of this material and explained the schematic, the general requirements, and a wave shape indicating the percentages of permissable harmonics. Also included was a proposal to be prepared by a registered professional engineer and submitted to the Company for its review.

Several months later Mr. Shirk contacted me and I arranged to meet him at his residence so that we could have further discussions on this proposed installation. Accordingly, representatives of the Customer Engineering Department, the T & D Department and Commercial Operations met Mr. Shirk and reviewed the various documents he had relative to the type of equipment that he planned to install. He explained that he planned to install a

fifteen kVA induction generator in an existing turbine hall that had been used previously for the generation of electricity. We then toured the location and observed the fine progress he had made in retrofitting the various conduits, valves and other devices required for the operation. We also inspected the turbine which was in place at that time. The actual generator was not installed, but his intention was to connect a belt drive from the vertical shaft of the turbine to the shaft of the generator. We then reviewed our electrical service to his residence and found that he was the only customer on a secondary service that had a transformer of sufficient capacity to handle the output of his machine.

Several months later we received a proposal from Mr. Shirt with all of the information provided by the registered professional engineer who he had retained. Also included were various documents regarding the installation, including a single line that showed where an isolating switch would be located. This proposal was reviewed by the Customer Engineering Department, who determined that it was a safe interconnection between the private generation and our system. I then prepared two contracts: one authorized Mr. Shirk to operate his generator in parallel with us; the second was an agreement to purchase energy based on our buy-back policy.

Last Christmas he energized the system. Since that time he has sold the Company more than 17,000 kWH, and his own electric bill has been reduced to the minimum charge.

PECO POLICY AND PROCEDURES FOR BUY-BACK

In May of 1977, under the direction of the Chief Executive Officer, Philadelphia Electric Company formed a committee whose assignment was to change the Auxiliary and Readiness to Serve Rider which existed in our tariff. Under that particular rider there was no provision for the buy-back of energy from private generators. We did have over a dozen large cogenerators operating in parallel with the system, but in all cases they operated at a heat balance that still made it necessary for them to purchase electrical energy from the Philadelphia Electric Company. That rider was modified to accommodate parallel operations at residences, and since that time it has been modified and the title has been changed to Auxiliary Service Rider. (Figure 1) This most recent modification includes the specific standby terminology used in the National Energy Act. We also prepared (back in 1977 and 1978) a document that described the requirements for parallel operation at secondary voltages. This included a schematic (Figure 2) which indicated the basic electrical arrangement that was considered satisfactory for such an installation. It was clearly indicated that this was not an absolute fixed arrangement since we realized that site specific adjustments would have to be made. We also included a sinusoidal wave shape that indicated the percentage of harmonics that we would find acceptable and required that the prospective private generator submit his conformance. (Figure 3) Also, we included in the document a formal proposal for the private generator to submit to the Company so that we could review the proposed installation and upon which we could make a decision as to its acceptability and determine any adjustments that we might require so that it might be made acceptable.

AUXILIARY SERVICE RIDER

Applied in conjunction with a contract at Rate......dated....................19...,

between...
(Name)

....
(Address)

and PHILADELPHIA ELECTRIC COMPANY

Rider Statement

Applicability. Service to a Customer, any part of whose electric requirements are regularly provided by other than Company-owned facilities, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rider.

Extent of Supply. The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

Control of Supply. In case the number of kilowatts contracted for is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types approved by the Company, to be furnished, installed, connected and maintained by the Customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

Parallel Operation. The Customer shall not at any instant operate any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Type of Supply. The following types of power supply are available:

Back-up Power supply is available to replace the Customer's own generating capacity whenever it may be interrupted on an unscheduled basis.

Supplementary Power supply is available to add to the Customer's own generating capacity on a continuing firm supply basis.

Maintenance Power supply is available to customers whose total load exceeds 1,000 kW to replace part or all of the Customer's own generating capacity. The supply of maintenance power will be on a scheduled basis that is acceptable to the Company and will be subject to interruption at the sole discretion of the Company. Maintenance periods will be limited to a maximum of three months duration and two occurrences per year.

Rate and Billing.

Back-up or Supplementary Power will be available to the Customer under a contract that will specify the total firm capacity that the Company could be required to serve at any time. The monthly billing for Back-up or Supplementary Power will be under the provisions of the normal service rate.

Maintenance Power will be billed under the provisions of the normal service rate except that charges will be prorated for periods of less than one month's supply and the 40% contract and 80% summer month ratchet of the normal service rate will not be applicable.

Distribution Facilities. Any investment in additions or changes to Company distribution facilities required to provide back-up power, supplementary power, or maintenance power will be paid by the Customer before the interconnection of Company and Customer facilities.

Liability. The Customer shall reimburse or hold harmless the Company for all losses to Company, Customer, or third parties; for all damage to Company or Customer facilities; or for all liabilities to third parties as a result of Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

Term. Annual, except, where otherwise specified by the firm rate.

....

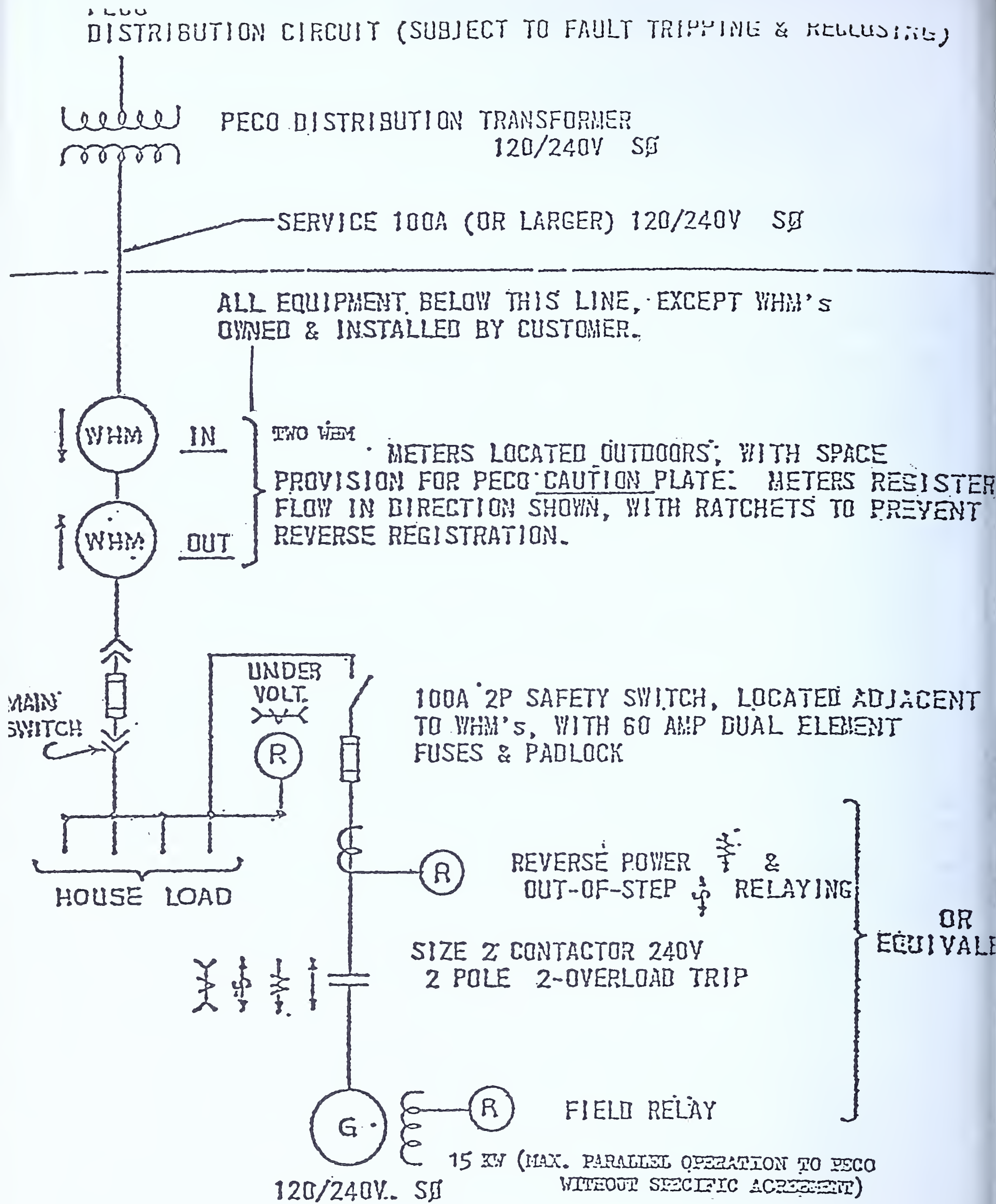
BY..
(Indicate Title)

PHILADELPHIA ELECTRIC COMPANY

BY..

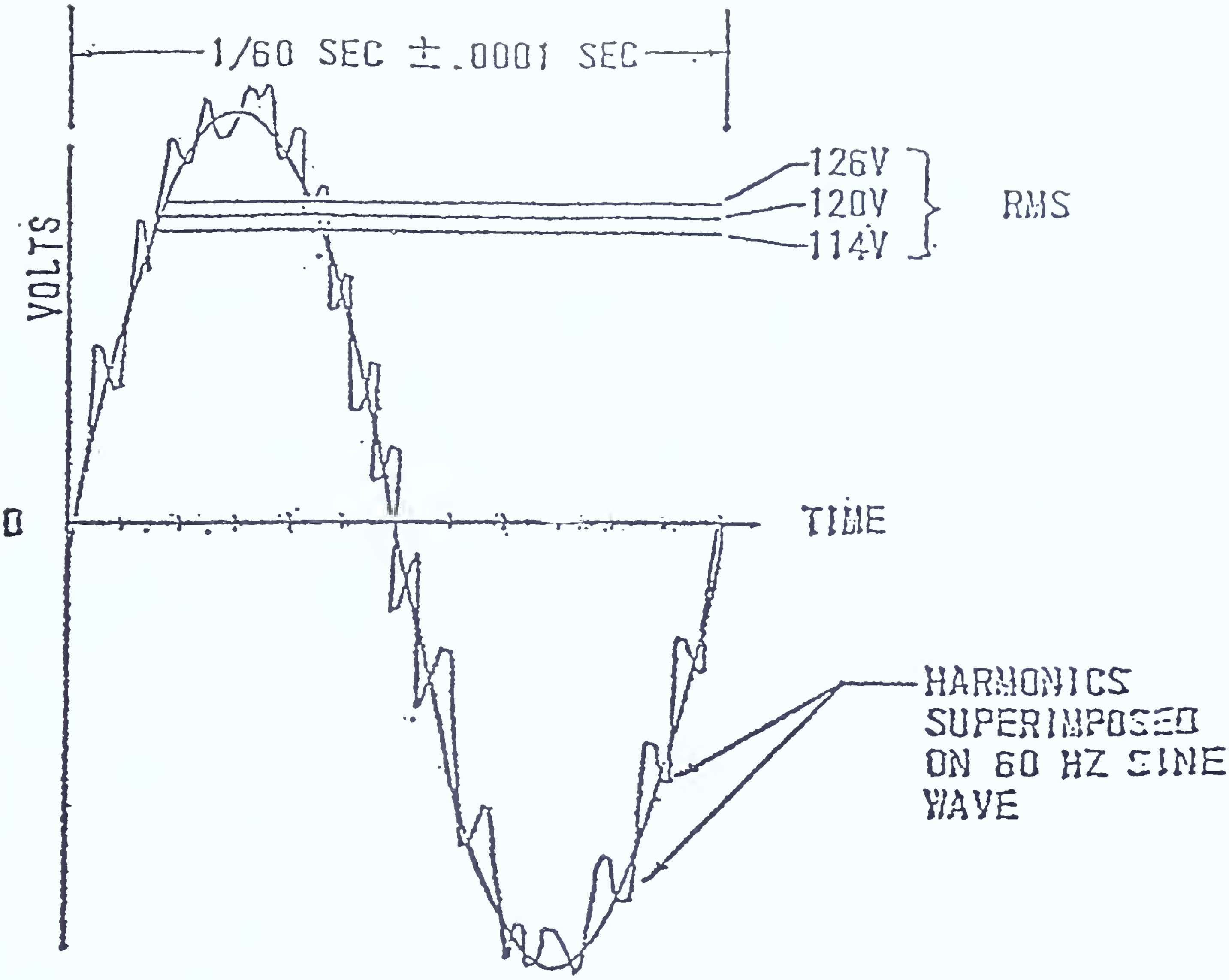
196-10164 REV'D. 5/80

FIGURE 1



7-21-78

FIGURE 2



THE VOLT-TIME GRAPH OF PECO SERVICE IS A SINE WAVE WITH ROOT-MEAN-SQUARE VOLTAG F 120V PLUS OR MINUS 6V, AND A PERIOD OF .0167 SECONDS PLUS OR MINUS .0001 SECOND. ENERATOR RUN IN PARALLEL WITH PECO WILL RUN AT PECO FREQUENCY. A TREND OF THE ERATOR TO RUN FASTER THAN PECO WILL RESULT IN INCREASED GENERATOR OUTPUT, AND A END TO RUN SLOWER WILL RESULT IN THE GENERATOR RUNNING AS A MOTOR.

DISTORTION OF THE SINE WAVE WILL BE ACCEPTABLE IF THE SUM OF ALL HARMONICS SUPE MOSED ON THE 60 HERTZ WAVE DOES NOT EXCEED 5% (ROOT MEAN SQUARE), AND THE LARGEST MONIC DOES NOT EXCEED 3% (ROOT MEAN SQUARE).

STANDARD 60 HZ WAVE FORM
WITH ALLOWABLE TOLERANCES

7-21-78

FIGURE 3

It was also necessary that we determine what was a reasonable price to pay for the energy that would be purchased from the private generator. As indicated by the dates I have outlined, we had arrived at this well before the final rules of the Department of Energy had been promulgated, and we were unaware that we had actually been establishing "avoided costs", which is a current "buzz word". We were completely unaware of it at the time and made the decision based on what we felt was fair to the private generator, to the other rate payers, and to the stockholders of the Company. Our policy was based on the fact that we purchased approximately 30% of our energy from the interconnection. Therefore, the energy that was supplied by the private generator would replace the need for purchasing that amount of energy from the interconnection. Accordingly we calculate the PJM billing rate to Philadelphia Electric Company and that value is paid to private generators. Also, the value reflects any hours in which we might sell kWh. For the small cogenerator we decided to pay the average value during the month, even though the PJM billing rate is actually established on the energy supplied in each specific hour. However, for simplification it was decided that in the cases of small installations we would use the average value. (Figure 4)

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PJM BILLING RATE TO PECO

Month	PJM Billing Rate to PECO	Month	PJM Billing Rate to PECO	Month	PJM Billing Rate to PECO
Jan. 79	22.2	Jan. 80	42.1	Jan. 81	48.45
Feb. 79	25.4	Feb. 80	39.2	Feb. 81	43.63
Mar. 79	19.7	Mar. 80	37.1	Mar. 81	51.76
Apr. 79	23.2	Apr. 80	29.9		
May 79	25.1	May 80	34.3		
June 79	25.3	June 80	31.2		
July 79	27.4	July 80	37.85		
Aug. 79	29.4	Aug. 80	37.34		
Sept. 79	31.5	Sept. 80	31.58		
Oct. 79	32.8	Oct. 80	36.16		
Nov. 79	30.6	Nov. 80	42.74		
Dec. 79	32.0	Dec. 80	49.01		

CEMAP Committee - J.R. Rocisch *All values are in mills/kWh JR 4/81

FIGURE 4

POTENTIAL FOR LOW HEAD HYDRO OF PECO SYSTEM

We estimate that there is the potential of 14 or 15 megawatts of generation on our system which should be capable of providing approximately 82 million kWh per year. (Figure 5) These represent the major dams with generating capacity varying from four or five hundred kilowatts up to 3 or 4 megawatts of capacity. I know that there are additional sites on the Perkiomen, Neshaminy and other creeks in the area which will be developed. However, these will be small units on the order of 25 KW or less. We have been contacted by various organizations relative to each of these sites that are listed. We have met with them in good faith and have explained our requirements. Payment policy for these larger installations is still based on the PJM billing rate to Philadelphia Electric Company, but our policy provides that magnetic tapes be installed to record the number of kilowatt hours provided in each specific hour. Since we also have available the hour-by-hour values of the PJM billing rate we are able to calculate the payment to which the customer is entitled for the energy he has provided in that period of time.

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Estimates Based on General Information

			Output x 10^3 KWH
Fairmont	Schuylkill River	2.8	14,800
Flat Rock	" "	3.7	18,400
Black Rock	" "	1.4	8,200
Norristown	" "	1.4	7,200
Vincent	" "	0.9	5,600
Plymouth	" "	-	8,700
Green Lane	Perkiomen River	0.8	2,700
Octoraro	Octoraro River	0.5	2,800
Union Mill	Delaware Canal	1.8	11,000
Nockamixon	Tohickon Creek	1.0	3,100
		14.3+	82,500

Total Sales 27 Billion KWH

$$\frac{82,500}{27,000,000} \times 100 = 0.31\%$$

JR
4/81

FIGURE 5

For these larger installations we have not prepared a formal document listing the rules and regulations for interface with the PECO system. Instead we have met with each of the prospective private generators to discuss site specific conditions. At such meetings we have in attendance representatives of our T & D Engineering Department, Customers Engineering Department, and a representative of our Civil Section, who is familiar with hydro power. These meetings have been fruitful, and we discuss freely items of concern. We will be preparing a document that lists some of the general requirements for connection at higher voltages. Such a document can be misleading because it does require site specific attention.

SPECIAL NEGOTIATIONS

The most critical item in developing a low head hydro is the condition ot the civil works that are in place and the extent of the new work that must be done to construct an operating facility. Where the civil works are in good shape, a megawatt unit might be installed for $600,000 and a standard payment policy is more than adequate to meet the requirements of the developer at such a site.

However, a developer requiring several millions of dollars of investment in order to construct a 3 or 3-1/2 megawatt installation will have problems with financing. Since the operator must be able to guarantee to the bank a minimum payment in order to meet their monthly payments. Additional problems revolve around the fact that there can be low years and certainly low months of river flow which would result in less than the required amount of revenue to meet the monthly obligations.

Even at large hydro installations (Figure 6), such as these figures listing the output at the Conowingo Site, you can see how the output per year varies from a billion kWh in some years up to 2 billion kWh in others. This

HYDRO POWER - PHILADELPHIA COMPANY SYSTEI

Installation		Stream	Capacity MW	Output x 10^5
1928 Conowingo	1970	Susquehanna River	512	1,677
	1975	" "	"	2.275
	1976	" "	"	2,065
	1977	" "	"	1.997
	1978	" "	"	1,700
	1979	" "	"	2,155
	1980	" "	"	1.240
1967 Muddy Run Pumped Storage	1980	" "	880	1,050 1,526
1980 Customer Installation 2 Mos.			0.005	.0081

FIGURE 6

represents a substantial difference in revenues. When one examines the monthly output, or expected output, from low head hydro installations, there are months during the summer in which the flow will be at a very reduced level. Because of this, the developer requires an agreement that will indeed provide him with an amount equal to about 80 percent of what his estimated monthly revenues would be if the flow had been normal as compared to months in which the water supply is adequate.

In addition, the initial few years of such installations, where there is a large requirement of capital, requires that the utility and the private generator examine possible solutions that will provide a special buy-back policy to enable the developer to obtain financing. In this figure (Figure 7) the straight line represents a possible escalation of the avoided cost of a utility. Let me stress that I intend these figures to be used only to illustrate a point, and I do not intend that they be tied to any specific utility or developer. The curve that has the knee in it represents the escalation of costs during the construction of the low head generating facility. During this span of time, because of the expected escalation in material and labor costs, it is expected that there will be a sharp increase in the required capital on the part of the developer. Then at the commercial date you can see the curve, which is the flatter curve, represents payments to the private generator. This curve which starts out at a value exceeding the value of the energy that the utility would pay based on avoided cost (or billing rate), is flatter because only thirty percent of the costs of the developer would be variable and subject to escalation and, therefore, his does not escalate at the same rate as the utilities avoided cost.

As you can see, we now have a type of scissors curve. I have used log paper in this sketch for the "Y" coordinate in order to flatten out the curve. If this had not been done, the curve would have risen exponentially and would not fit on a reasonably-sized piece of paper. As you can see, the area to the left of the intersection represents money that is being paid to the developer over and above that which is the true value of the energy based on avoided cost. The area between the curves to the right of the point intersection or crossover now indicates savings to the rate payers of the utility because the private generator is now being paid less for the energy than the avoided cost. Now, obviously one first has to pay off an amount equal to the triangle to the left of the intersection, with consideration given to present worth. In these calculations reasonable attention to the various escalators should make it possible over a period of twenty years for the overall savings to the rate payers to be 10 or 15%.

There are other methods for negotiation. For instance, a flat rate of compensation could be used for the first four or five years of the installation that would be based at 1.15 or 1.2 times the avoided cost. This would provide the "front end loading", and after the crossover point it would be possible to tie in the rate paid to the private generator to a fixed percentage and some bases of the avoided cost.

ECONOMIC ANALYSIS FOR A LOW HEAD HYDRO INSTALLATION

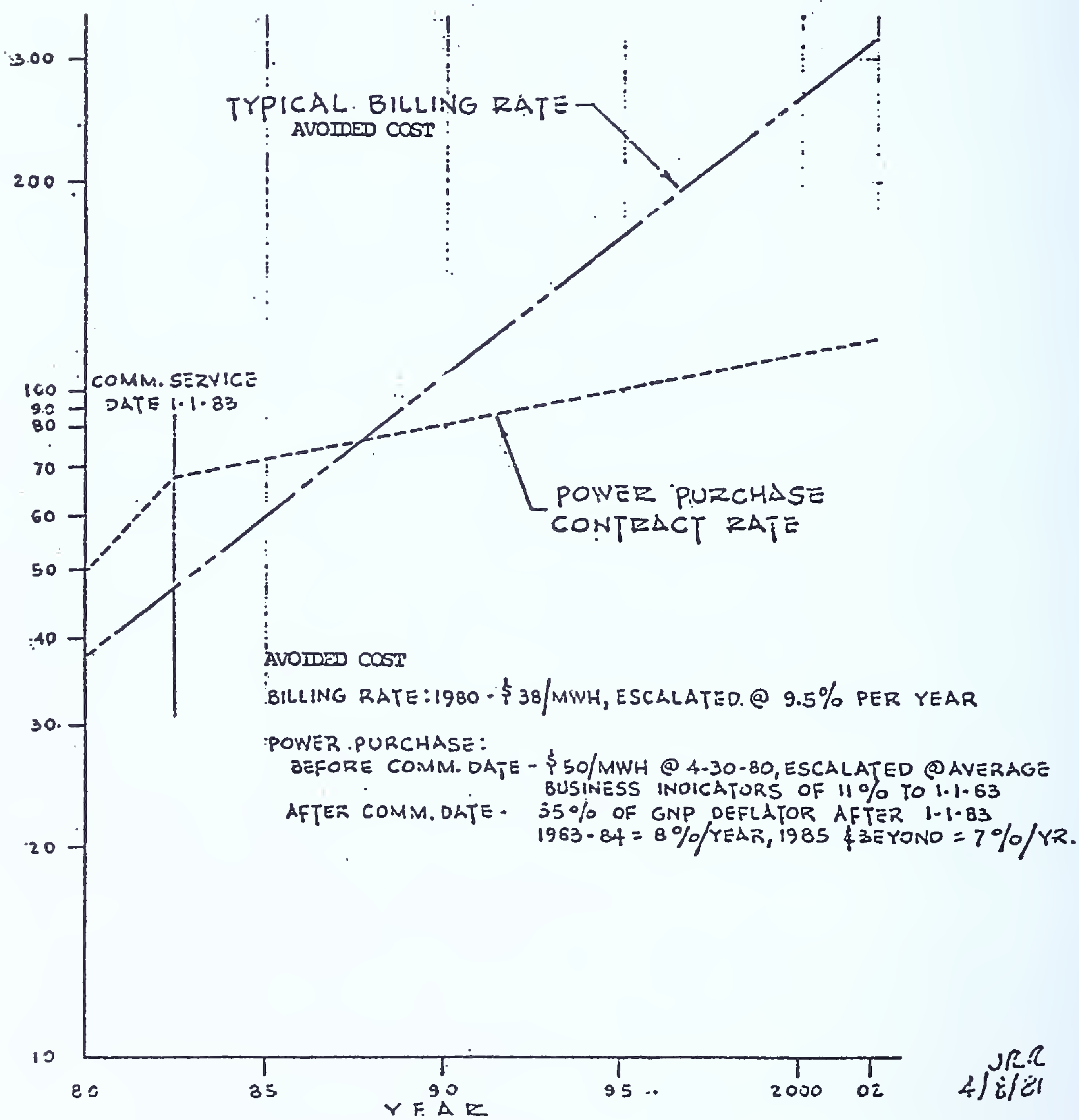

FIGURE 7

Obviously, these are special contracts and would have to be negotiated. It does require imagination, creativity and sensitivity on the part of individuals involved, and since it would be a departure from true avoided cost, it would require that the utility commission give their approval to such a contract prior to documents being signed. This would be necessary to protect the rate payer and the utility since these costs would be included in the fuel adjustment calculations. Therefore, it would be of great importance that authorizations and approvals be obtained from the commission in negotiations of this type.

It also should be remembered that these special negotiations should only be considered in those cases where there is a true need. Obviously, those installations which have good civil works and which do not require extra amounts of financing cannot be entitled to special considerations.

Such negotiations must be worked out in good faith. It is always difficult to depart from an established policy because it could indeed open up Pandora's box since everyone may feel that they are entitled to special considerations. However, in these days of energy shortage I believe that special efforts, creativity, and imagination must be made by all parties concerned to utilize renewable energy sources.

SUMMARY

Low head hydro in Pennsylvania does have potential for helping our energy crisis. The order of magnitude of its contribution is quite small when compared to overall energy needs. Because of the possibility of successive years with low flow, and certainly successive months with low flow, it cannot be depended on and must be backed up with conventional generation. However, the kilowatt-hours that they can provide certainly does replace energy that could be provided by non-renewable sources. I know that at Philadelphia Electric Company we are anxious to explore new paths and arrive at satisfactory negotiations where possible.

UTILITY CONTRACTS AND STATE LEGISLATION

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It's nice to be here, and I think the old saying about the hazards of being last on the program have probably come true in my case today. One of my topics has been pretty well chewed over; that is, utility contracts. So what I think I'll do is spend the bulk of my time talking about state legislative activity.

The Virginia Hydropower Association was formed in January of this year, largely on the basis of a fairly urgent agenda which had been created in the circles of government. There were seven cases pending at the State Corporation Commission to set avoided costs, rates and other terms and conditions of the relationships between qualifying facilities and utilities. While we hadn't gone through those cases at that point, we could see from the prefiled testimony that vast areas of the state were going to be a virtual wasteland from a small hydro standpoint because of the substantial differences in the utility filings on avoided costs. It became apparent rather quickly that an important legislative objective would be to facilitate the creation of some leverage on behalf of qualifying facilities. So that if they were not fortunate enough to be located in the service territory of one of the utilities paying relatively higher rates, they would have some option, some way to deal with that.

What we decided to do was to seek the passage of legislation which would to a certain extent uncouple the qualifying facilities from electric utilities by authorizing them to engage in sales at retail. As some of you may know, PURPA says very little about the ability of qualifying facilities to engage in sales at retail. It simply mandates a wholesale transaction between qualifying facilities and utilities. It specifically says that it does not authorize qualifying facilities to sell directly to end-users. But the legislative history of PURPA also made it clear that that did not preempt the states from going forward and authorizing qualifying facilities to sell at retail. So we sought the passage of legislation that would accomplish that. Essentially, what we did was define qualifying facilities out of the definition of electric utilities. You can sell at retail as long as you're willing to be an electric utility. Of course, the typical qualifying facility couldn't commence to undertake that regulatory burden. The end result was that House Bill 1609 was enacted; it becomes effective on July 1 of this year.

We had some interesting lobbying going on there; and the final result was not exactly what the initial bill looked like, but what it does is it permits small hydro facilities to make sales at retail to a limited number of nonresidential end users. We thought the General Assembly would have a difficult time saying, "Yes," to allowing nonregulated power producers to sell to the residential sector, and we didn't, frankly, think that would be very important anyway; so the bill limits the authority of qualifying facilities to sell at retail to nonresidential users. It also limits the number. We picked a number -- it happens to be five. Obviously, by sheer force of practicality, there are some other limitations. Qualifying facilities do not have the power of eminent domain. If they are not situated very close to potential commercial customers, they have no ability to condemn any rights-of-way to hook up. So if the privately-owned land in the hands of third parties intervenes between the site and your potential customers, you simply have to negotiate easements.

Now there's another fairly important amendment to that bill that I think has some interesting potential. It would allow a qualifying facility to sell some or all of its power at retail. That brings to mind some possibilities. If you have a site that is sufficiently close to a substantial commercial end user that you can overcome that type of problem, you may be able to sell your power, on peak, to the utility and get the on-peak rate from utility and have a standby arrangement to sell whatever you've got off peak at retail on the grounds that the retail customer probably is going to be paying a lot more for his power than the utility will pay you off peak. So you could have a mix of sales at wholesale to the utility during on-peak hours, sales at retail to somebody else during off-peak hours, and improve your revenue flow.

You can turn that around in some ways, perhaps. If you have a power purchase contract under which your maximum guaranteed capacity to the utility is set at a fairly low level, as it undoubtedly would be in the case of hydro, you could perhaps contract to make spot sales of on-peak power to the extent that you happen to have excess capacity to industrial users. If that occurs during the summer months -- in the case of VEPCO -- there will be a lot of industrial users, if they are on the rate schedule that calls for a demand ratchet to be applied to their billings, that would dearly love to have some other source of power on peak. Because, as I think some of you probably know, industrial users who are faced with a demand ratchet pay for that one-time

highest demand that they impose on utility systems all year round by virtue of the demand ratchet clause. So, the possibility of engaging in simultaneous sales at wholesale and sales at retail, I think, is an interesting one. It probably will not have widespread application because obviously you have to be fortunate enough to have a feasible site that is sufficiently close to some commercial end users who are willing to contract with you before you can make it go. But if those conditions exist, then I think there is a possibility of using this legislation to bootstrap a better revenue picture.

In the energy area, the sleeper of the year was a bill that radically enhanced the authority of a state agency called the Virginia Fuel Conversion Authority. That agency was referred to by one of the earlier speakers. It was created last year to try to lure some Federal money down here for a pilot project in coal gasification. That didn't come to pass, so Senator Andrews from Hampton put in a bill this past year that essentially changed the whole thrust of that agency into a sort of benign state DOE. And when I say benign, I mean somebody who you might be able to get some financial help from but isn't going to impose any regulations on you. The Fuel Conversion Authority on July 1 will have the authority, if not the financial wherewithal, to render financial assistance for feasibility studies, to issue revenue bonds, to joint venture the development of sites with private entities. I think, considering this dramatic change in the thrust of that agency, it's going to take some time before they can find a way to market bonds and pick out some good projects to commence with. It's not limited to hydro. They can provide that type of assistance to anybody in the alternate energy field. Probably they will be involved with some municipal waste-burning facilities to generate power on a cogeneration basis. Certainly someone involved in the Hydropower Association will be going to see them, and I know they'll be receptive because the director of the agency just told me he would be receptive to entreaties that they undertake to assist in bringing on line some small hydro projects in Virginia.

There was another bill which wasn't terribly dramatic, but I think the bottom line is fairly significant. Currently, and until July 1, if you want to be a small hydro developer in Virginia you have to go to the State Corporation Commission and go through a fairly elaborate licensing procedure which essentially involves consideration of utility-type factors. Because when that particular law was established it was just assumed that the only people who would be generating power at dams would be electric utilities. Fortunately, the State Corporation Commission decided, very wisely, that there's no need for them to be licensing anybody except electric utilities. You all have to go through quite a bit of licensing procedures from a power production standpoint, from a dam safety standpoint, by the State Water Control Board and lots and lots of other people and certainly didn't need an extra layer of licensing to go through. So that requirement is being disposed of. Again, effective July 1.

We already have on the books a statute which authorizes local governments to put alternate energy facilities into a special tax classification for purposes of local real estate taxation. That, I think, was enacted without any idea that there might be something around called small hydro. But we have gotten an interpretation of that statute from one of Eric Page's colleagues, who represents the Virginia Department of Taxation. He has concluded that it does apply to small hydro. Therefore I think that a step that anybody who

is developing small hydro in Virginia should take is to petition your friendly board of supervisors if you're in a county, or city council if you're in a city, to go ahead and implement that authority. It's not self-executing. The local government has to come along and do something and say, "Yes, we think we want to promote this, so we will enact an ordinance that classifies alternate energy production facilities separately and puts them into a lower tax rate for real estate tax purposes." They could probably simply make them tax exempt if they wanted to. So if you're very good at lobbying, you might go for outright tax exemption.

There are some other state legislative issues which we have not addressed, just because we have short sessions in Virginia and there's not a lot of time to deal with everything that you can think of. However, there is some litigation occurring at the federal level which tends to make this particular industry somewhat more uncertain than it already is because it has at least a potential, theoretically, to disturb the federal legal framework within which you operate. It seems to me that in order to enhance the stability of long-term contracts which would remain subject to state regulation, a state PURPA law might be a very good idea. It would have to match the federal law. Obviously, it couldn't have the effect of forcing a different set of results, but that would be nice insurance against the prospects, however remote it might seem to be, that the federal legal framework would suffer some judicial damage.

The relationship between these two topics that I have is somewhat tenuous, but there is, as I've said, some nexus between the contracting process -- at least for purposes of House Bill 1609 -- and state legislation, so I think I'll shift over to the contract process. First of all, I'll just quickly review a few fundamental notions. The FERC regulations only require state commissions to promulgate tariffs, rates and terms of service for qualifying facilities of 100 KW or less. If a state wants to go beyond that, it's optional. The hearing examiners in the Virginia cases had uniformly said, "Let's just promulgate a tariff for the 100KW facilities and under and allow the parties to negotiate what they want to do on those that are larger." That brings the question to mind of what is the precedential effect of the rate determinations that the commission will be making for the small facilities when the larger ones negotiate their contracts? There's a divergence of view there.

Virginia Electric Power Company (VEPCO) appears to be of a mind that contracts with larger facilities will be negotiated adhering very closely to the rates and terms of service that have been established for the small ones. At least that's what their attorneys said in the documents that they filed in the Section 210 case which involved VEPCO. Appalachian Power Company (APCO) on the other hand, during the course of the Section 210 case, took what apparently was a substantially different view. That was that there was no necessary connection between what they might negotiate for larger facilities and the rates and conditions of service established for the 100KW and under facilities. I wouldn't begin to venture a guess as to what sort of legal problems there might be if they're negotiating all kinds of different rates with larger facilities. I think that they take the view that the State Corporation Commission essentially has no role in approving or nonapproving the contracts that they might enter into with larger facilities. In a sense that's true, because PURPA authorizes any utility and any qualifying facility to contract in any manner they want to. But PURPA does not limit the ability of a state

utility commission to throw out the costs that a utility incurs in a contract with a qualifying facility when that utility is coming in for an increase in rates. If a utility enters into a long-term contract with a 500KW qualifying facility that calls for payments that are greater than, perhaps, the regulators think justifiable, they won't do anything about that contract -- at least initially -- but they might not allow that utility to pass those costs on to their consumers the next time that utility comes in for a rate increase. So it seems to me that small hydro people probably should seek to get some explicit acknowledgement from the State Corporation Commission staff, at least, that a contract that's been executed is reasonable, because a utility may not contract with impunity as far as the regulators establishment of their rates to consumers is concerned.

While the constitutional law in the area of state action which impairs the obligations of contracts is always changing, I do not think that if you enter into a contract that sets a certain rate for 10 years, and there's no state approval of that contract, that you are immune from regulatory action three or four years into the contract, which has the effect of impairing it. So I, just to be very very safe, I would think it would be appropriate, once you've got your contract, to take it down to the commission and say, "This is where we're going. We would like some expression from the commission that it's reasonable."

There are zillions of provisions that probably should go into these contracts, and I think most of them occur naturally in the course of sitting down and discussing them. In the area of payments: in Virginia, the concept of levelized payments will probably be a make-or-break concept in almost every case. It's difficult for me to see, unless you've got a facility that you can bring in for six- or seven-hundred dollars a kilowatt in capital costs -- and there are not going to be many of those -- how people are going to get very far without something in those contracts approaching a levelized payment. You've heard Mr. Barr give the VEPCO philosophy about the merits of levelized payments. The Hydropower Association is going to attempt to act as a sort of collective bargaining agent for hydropower people and work out a master contract with VEPCO which then each would-be small power producer can take and refine for all the site's specific considerations. But in that master contract we are going to try to get some recognition of levelized payments.

Now, how are we going to do that? Well, we would start with VEPCO's ten-year forecast for marginal energy costs. They have filed that information. They show that by 1989 with no increases -- real or due to inflation -- the marginal energy costs on peak will be up around 7-1/2 cents. Now it seems to me that since payments are only made to the qualifying facilities as they deliver the power throughout the life of the contract, there's no basic problem in terms of rate payer subsidization -- if you get an average rate to start with, based on the ten-year forecast of where their marginal costs are going. A previous speaker said that you might want to stay away from that because then that gives you something on the front end, but you're locked into less than adequate returns on the back end. Well, if you can't get enough on the front end to get going in the first place, then there's no sense in worrying about the back end. Plus, these forecasts are in 1980 dollars. Your average levelized rate would still trend up for inflation and real-price increases. So I think that it's inflation and real-price increases that are going to create the biggest portion of that spread between what your operating costs are and your gross revenues are going to be over the life of a project.

There are other ways to approach it. You don't have to get purely levelized. You might be willing, or the company might be willing, to have it partially levelized. In other words, maybe in the years one through the midpoint of your contract (a ten-year contract, say, years one through five), instead of accepting fully-levelized, you would take maybe 1.2, 1.3 times what actual avoided costs are supposed to be in those years. Maybe you would settle for something less than full avoided costs in order to get levelized payments over the life of the contract. There are some mortgage analogies which can be brought into play here. There may be ways to give the utility a security interest in your business to protect against Brit Gilbert's Brazilian scenario. A utility can have a 49% ownership interest in a qualifying facility and it's still a qualifying facility. You may be able to mortgage your business to the utility, or 49% of it, as a way to hedge against the south-of-the-border syndrome. I think the idea of escrowing portions of net revenues as a protective device for the utility which is concerned about overpayments in the first half of the contract could help. Of course, if you have no access to that for working capital purposes, then it could also kill you. So that would have to be a fairly sophisticated contract provision in order not to work a hardship. But I don't think the problem of the nakedness of the utility during the first half of your contract, if its got levelized payments, is an insurmountable problem. It just requires a little creativity, it seems to me.

Except for those things, let me just touch briefly on a few other quick points. In the form power-purchase contracts that all of the utilities involved in the Virginia Section 210 cases filed, the treatment of interconnection cost, I thought, was rather interesting. In some cases they called for the qualifying facilities (QF) to make contributions to the utilities in aid of construction; in other cases the QF simply paid for it up front; in other cases it would be amortized over a period of anywhere from whatever the parties could agree on to one year. But the status of that investment was never clear in terms of who owns it. It seems to me that if the qualifying facility is paying for interconnection equipment, you want to get investment tax credits on all the hardware you're paying for. In order to do that I believe -- I'm not a tax lawyer, but I believe -- you either have to own it or lease it. So, if the utility is uncomfortable with the idea of you owning the interconnection equipment, then I think that an approach to that problem would be simply provide that the utility owns it, leases it back to you for the term of the contract, along with a provision agreeing to pass through investment tax credits. They couldn't get the investment tax credits on it if they made the investment. I think it would just be unreasonable on the part of the utility to withhold agreement to pass through the investment tax credits if this type of property is put in a lease category.

Line losses! Line losses are a site specific consideration, and so it's not going to be possible to deal with that in terms of actual numbers in any master contract that might be developed by the association for use by the industry. But it's a major consideration. Mr. Barr referred to that as an element that emerged in the VEPCO case, for example. The numbers which we generated from the company during that case suggested that in the case of energy credits the loss factors would call for an increase in those by something on the order of 8% or 9%. I'm sure that most of you understand what the effect of line losses is. If it takes 1.2 kilowatt hours of energy

at the generation level to deliver through transmission and distribution lines 1 kilowatt hour of energy, and you as the qualifying facility supply to the utility at the distribution level of 1 kilowatt hour of energy, then you have enabled the utility to avoid the cost of generating 1.2, so that's a benefit you should get if it's not dealt with in the numbers filed by the utility. It really can't, because you might not be tying in at the distribution level. You might be tying in at some other level and then the loss factors would be different. But it requires, I think, a site-specific calculation, qualifying facility by qualifying facility, of what loss factors are applicable in your situation. In the case of demand credits, the numbers filed suggested that the loss factor there would be 10% to 12%. If you are tied in at a distribution level then your demand credit would be $4.50, or something like that, per month. The loss studies that the company does, I think should be updated annually, and so any contract provisions on loss factors, I think, should provide that they can be reopened.

Let me just close with a comment on demand credits. That is a tough one for hydro for obvious reasons. As I understand the FERC regulations, you do not have to be 100% renewable energy in terms of your source of energy in order to be a qualified facility. Bill, you can check me on this, but I think you can have as much as 25% of fossil fired generation and still be a qualifying facility. That means that it makes some sense, depending on the circumstances, to put in a small combustion turbine to boost your minimum dependable capacity so that you get that credit all the time. You and, I think, the Association when we get into our contract negotiations, also need to be concerned about what is the reference point against which you'll be measured in terms of availability. Some utilities are taking the approach that you just forgive the first 10% of the hours in a year and then, for the balance of them, if you are available 85% of the time you qualify for 100% demand credits. In VEPCO's case, at least during the hearings, they took the position that if you are as available as they are you qualify for 100% of the demand credits. I think that would be a preferable result as opposed to some industry standard, but I'm not sure that that was a well-thought-out answer and it may be that the company, when we get down to negotiating contracts, will take a slightly different position.

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